Whitepaper

# Mind the Gap
# The black hole at the heart of the UK's energy supply


R e l e a s i n g   y o u r   p o t e n t i a l

# Introduction

This paper sets out to scale the looming 'energy gap' by bringing together research from a range of sources. The paper is structured as follows:

Page

**02 Foreword**

**03 Summary**

- A summary of 'optimistic' and 'conservative' scenarios for the energy gap for 2005-2010; 2010-2015; 2015-2020 in periods of average demand (normal demand) and peak demand (typically around 6pm on a very cold winter's day);
- An overview of the potential economic impact of the gap;
- Recommendations on key measures to close the gap as input to the forthcoming energy white paper.

**08 Background to the Energy Gap**

- Sets out how energy usage is measured within the UK and the ways in which an energy gap needs to be calculated
- Describes current supply
- Summarises why a gap is appearing across the energy chain:
  - the source of the raw fuel for energy source
  - generation: turning raw fuel into energy
  - transmission and distribution - moving that energy to homes and businesses
- Summarises options to fill the gap and the opportunities and risks of the different approaches.

**12 Scenarios**

- Provides energy provision and gap scenarios for three periods: 2005-2010; 2010-2015; 2015-2020. For each period the paper considers an 'optimistic case' and a 'conservative case'. These are derived by using different assumptions for the opportunities and risks above. For each scenario the paper provides:
  - Summary graphs showing optimistic/conservative cases for average/peak demand
  - A consideration of whether the conservative case is realistic
  - A table of assumptions that underpin the scenario modelling.

**25 Appendices**

These provide the basis for the detailed analysis behind the scenarios:

- A: Energy measurement
- B: Energy demand;
- C: Current supply
- D: Decline in supply
- E: Future supply options
- F: Scenario assumptions
- G: References
- H: Population statistics

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# Foreword

**Kieron Brennan**
Managing Director,
Energy & Utilities
LogicaCMG

**There is a looming energy crisis in the UK. Domestic prices have risen 93 per cent in two years, we have become a consistent net gas importer for the first time in 30 years and in March this year National Grid issued its first ever 'balancing alert', to warn industry that it may need to shut off their gas supplies.**

This crisis is primarily caused by the decline in our indigenous fuel and the ageing of our generation capacity. There is now a significant risk of an 'energy gap', where the supply of energy is no longer sufficient to cope with the levels of demand, leading to voltage reductions and power cuts.

The government is in the midst of preparing an energy white paper to identify ways to address the future provision of the UK's energy supply. This vital work requires a clear understanding of:

**what size** the gap might actually be, and

**when** it might occur.

This paper sets out to size the 'energy gap' by drawing together conclusions from a wide range of available research and subjecting these to a rigorous scenario analysis.

In particular, LogicaCMG is concerned that the current focus is heavily on energy provision post 2020. It is our view that a sizeable gap could occur much earlier, circa 2015. During this timescale we will see significant closures in our nuclear and coal fleet, but it will be much too early to build nuclear or significant renewables capacity - we have already started to see significant issues with the nuclear fleet this year. We welcome the influx of gas through the Lanegeled pipeline this year, but dependence on imported gas is not without risk as we learnt last winter.

Further, the whole pattern of our energy management could change. At the moment most power station maintenance is undertaken in summer, enabling high availability in the winter. However, this summer we have already seen the impacts of global warming driving up summer usage through air conditioning which caused a national outage alert in July; the future is uncertain.

LogicaCMG has been at the forefront of energy change worldwide for the last 30 years. We passionately believe in the need for a safe, secure energy supply. We are already starting to play a key role in enabling the low carbon energy economy through smart metering. We have brought our expertise to bear in developing this paper to help in creating a clearer understanding of the problems facing the UK and the challenges the Energy White Paper must address.

Kieron L

# 1. Summary

## No water...., no gas...., no electricity....?

**A flurry of hosepipe bans and drought orders raised the spectre of our water supply being cut off this summer. Last winter, many UK industrial companies received warnings to shut down as our gas risked drying up. Is our electricity supply next? Is the looming energy crisis going to return us to a world of power cuts and a three day week?**

The government is in the midst of preparing an energy white paper aimed at identifying ways to address the looming gap in the UK's energy supply. This vital work requires a clear understanding of *what* the gap might actually be and *when* it might occur. This paper focuses primarily on our electricity supply and sets out to size the gap by drawing together conclusions from a range of available research and subjecting these to a rigorous scenario analysis.

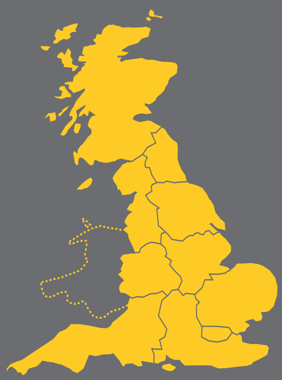
The paper considers the potential gap for **average demand**, the electricity demand for a typical average day, and for **peak demand**, electricity demand at the peak time of day (around 6pm) on a very cold winter's day. It also refers to the situation in a '1 in 10' winter, when demand may be 5 per cent above the peak. For each situation the paper considers an **'optimistic case'** and a **'conservative case'**, based on differing assumptions for supply and demand for energy.

> "The risk of a gap is very real. The impact on our business and social framework should not be underestimated. These issues can and must be addressed."

# 04

## The key conclusions from these scenarios are:

£7.9bn cost to UK economy



### 2010

**Optimistic case**: It will be possible to meet peak demand with a 15.5 per cent contingency. This is below the 24 per cent long term contingency that has historically been used, but within the short term 10 per cent contingency. It is acceptable given the relative short term and advances in energy technology and the current operational regime.

**Conservative case**: There will be a gap of nearly 5 per cent in energy supply and no contingency at peak demand. This is equivalent to an area the size of Wales losing all electricity for several days in winter, with a cost to the UK economy of £7.9bn. As there is no contingency this effectively raises the gap to nearer 15 per cent - equivalent to the great storm of 1987.

£91 - £108bn cost to UK economy

### 2015

**Optimistic case**: It will be possible to meet average demand with a 21 per cent contingency, close to the acceptable historic level. At peak demand there is only some 4 per cent contingency, raising significant risks of major power outages.

**Conservative case**: There will be a 23 per cent gap in energy supply at peak demand. This is equivalent to an area the size of London and the South East losing all electricity at peak times over a number of days in the winter. Even at average demand there is a 9 per cent gap, equivalent to Eastern England losing supply on a normal day. This could cost the UK economy £91 - £108bn.

£153 - £192bn cost to UK economy

### 2020

**Optimistic case**: It will be possible to meet average demand with a 41 per cent contingency and peak demand with 17 per cent contingency - outside historic good practice.

**Conservative case**: There will be a 31.5 per cent gap in energy supply at peak demand. This is equivalent to an area from Scotland to the Humber Estuary losing all electricity at peak times over a number of days in the winter. There is no contingency, effectively placing half the country at risk. Worryingly the gap could be up to 16 per cent at average demand, equivalent to all the area south of London losing supply on a normal day. This could cost the UK economy £153 - £192bn.

## The Potential Economic Impact of the Gap

“We are entering unknown territory. It is not obvious how the energy gap will manifest itself, what the individual impact will be on particular industries, regions or consumers and what the impact will be in the economy as a whole.”

Energy outages are becoming a more common occurrence across Western economies, in 2006 substantial power outages hit Germany and France affecting over 5 million people. There is growing research that provides a basis to begin to assess the economic impact. These make sober reading:

- **New York & Canada Blackout**
  This blackout in 2003 is estimated to have cost between **$6.8bn and $10bn**, even though it lasted only 4 - 60 hours. [26] [27] [28] This blackout affected 50 million people and an economic area of £1,100bn, [31] It is hence broadly equivalent to the size of a complete UK blackout. The blackout had an average cost of £5m for each **GWh loss**.

- **Berkeley Lab Model**
  This renowned institution in the US has estimated the current cost of supply interruptions to the US economy at **$79bn**. This is *without major interruptions* of the kind likely to be incurred under the energy gap. [29] Berkeley estimate that an hour‘s outage will cost:

| | |
|---|---|
| • Consumers | £2 |
| • Small Medium Enterprise (SME) | £800 |
| • Industrial & Commercial | £8,500 |

  Hence a two day‘s outage could cost UK consumers £100 and SME‘s nearly £12,800. With 1.1 million SMEs in the UK, this cost could be huge. Based on the 2003 US experience, 4 per cent of affected I&C companies lost $1m an hour, [26] or £10,000 a minute in UK currency.

The basis for these costs is factors such as:

- Spoilage and waste - estimated at $350 - $1bn for the US blackout
- Lost output. For example the Ohio Manufacturers Association estimated the cost to its members of the 2003 blackout was $1.08bn.
- Lost income to workers who are not paid or placed on short term working
- Lost income to related industries
- Cost to government agencies of blackout management, estimated at $15 - 100m for the 2003 blackout
- Cost to the power industry of rectification of problems and overtime to try and sustain supplies

We have applied these figures to the potential energy gap to get the economic cost of any outages in line with our scenarios.

**2010**

In 2010 we foresee a risk of a **5 - 15 per cent** (allowing for contingency) gap at peak times. A likely scenario is that this would be managed by asking energy intensive users to curtail production. These users, from industries such as aluminium, steel, glass, refineries, bricks, lime and cement, Chlor-alkali, paper and manufacturing use 5 - 6 per cent of UK gas. Diverting from these users could free up gas for homes and gas power stations to maintain electricity supplies.

The cost to these industries of shutdown has already been modelled for the DTi: [30]

| 1 day outage: | 3 week outage: | 6 week outage: |
|---|---|---|
| £188m | £3951.39m | £7902.79m |

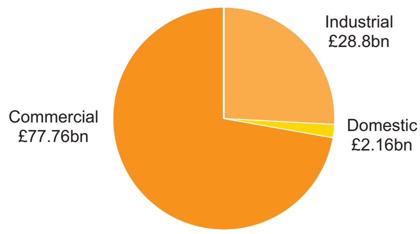
The cost of the gap could therefore be **£7.9bn** if sustained outages are required. These would directly affect **7,235 firms and 349,000 employees**. [29]

**2015**

In 2015 we foresee a risk of a 9 per cent gap at average demand. This is effectively a constant 9 per cent shortfall in energy provision. This would have a profound affect on the UK economy:

- UK GDP is £1,200bn.This gap places 9 per cent of that at risk. The economic cost could therefore be **£108bn**.
- An alternative measurement can be gained by using the US measurements of £5m per GWh lost. There is a persistent shortfall of 4 GWh per day. Assuming this cost is borne on a full 24 hour basis gives a cost of **£180bn**. Even assuming the cost would only apply to a broad 12 hour working period gives a cost of **£91bn**.

Taking the Berkeley Labs analysis, the cost to different sectors of a £108bn 'gap' would be:




Note that this a 'conservative' not a 'worst case' estimate. The figures could be far worse. They are based on average (9 per cent shortfall) not peak (23 per cent shortfall); they represent a standard winter, not a '1 in 10' or '1 in 50' winter; they do not consider potential decreases in plant availability caused by higher summer demand.

## 2020

In 2020 we foresee a risk of a 16 per cent gap at average demand. Using the analysis as above gives:

- GDP base: This gap places 16 per cent of GDP at risk. At 2006 GDP scale, The economic cost could therefore be **£192bn**.
- US base: Assuming this cost is borne on a 12 hour working period gives a cost of **£153bn**.

As previous example, note this is a 'conservative', not a 'worst case' scenario based on average rather than peak demand.

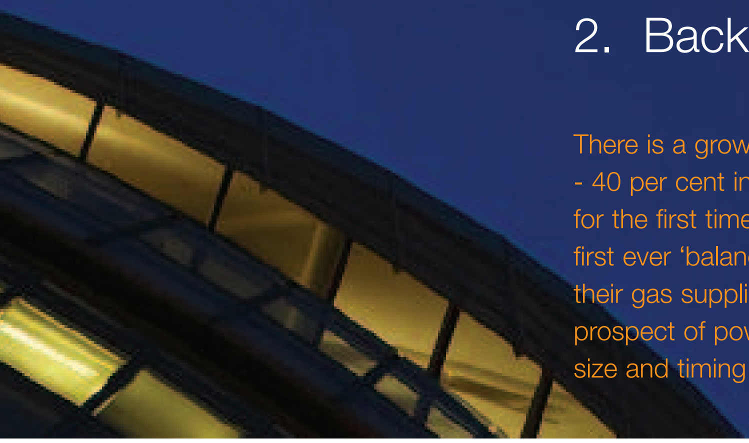
## The Way Forward

The economic impact highlighted in these scenarios is huge. However, if a 4 - 60 hour power outage can cost the North East US and Canada $6.8bn, then it is not difficult to see why a sustained gap will have the impact noted. Further, it is important to note that these figures represent a 'conservative', not an ultimate 'worst case'.

What then is the way forward? The purpose of this paper primarily is to draw attention to and scope the problem, not identify definitive solutions - that is the role of the Energy White Paper. However, based on these findings, in the first instance, we urge the government to:

- Provide a mechanism to enhance gas storage. In any energy future, the UK will be dependent on gas, but by 2014 80 per cent of this could be imported [32]. The UK only hold two weeks storage compared to 2-3 months in Germany and France. This is an unacceptable risk.
- Provide a mechanism to expedite development and usage of clean coal. Coal stations can be built by 2015, planning regulations permitting, and this provides a potential low carbon contribution to our energy needs. It should again be noted however that the bulk of our coal is imported, leaving us as a small competitor for coal against the burgeoning Far East economies.
- Establish a clear energy policy framework with intra and inter-party commitment to enable the private sector to make investment decisions and hence provide a sustainable and enduring energy infrastructure.
- Establish clear guidance on how a future price of carbon will be derived, again to enable the private sector to make investment decisions.
- Make it a top priority to extend the life of current generation capacity.
- Streamline planning regulations to facilitate storage and generation development
- Maintain a commitment to diversity of fuel sources
- Champion a clear European energy policy, with particular emphasis on gas provision.
- Accelerate the development of energy efficiency and local energy provision.

The risk of a gap is very real. The impact on our business and social framework should not be underestimated. These issues can and must be addressed.



# 2. Background to the Energy Gap

There is a growing energy crisis in the UK. Domestic prices have risen 30 - 40 per cent in two years, we have become a consistent net gas importer for the first time in 30 years and in March this year National Grid issued its first ever ‘balancing alert’, to warn industry that it may need to shut off their gas supplies. There is a significant risk of an ‘energy gap’, with the prospect of power cuts. This paper uses existing research to establish the size and timing of this gap.

## 2.1 Sizing the Gap

It is important to understand the pattern of energy usage and supply to accurately size the gap. This paper uses three accepted measures for demand:

**Average demand**: Average electricity consumption in Great Britain[1] is currently running at around 39 GigaWatts[2]. This increases by about 3 GW in winter and decreases by around 3 GW in the summer. [23]

**Peak demand**: The average consumption pattern varies significantly according to time of day and year. The current annual peak in consumption is around 60 GW. This typically occurs on a cold winter’s weekday around 5:30-6pm pm. [23]

**‘One in ten' demand**: exceptional demand, for example around 7pm on a cold winter’s day during an exceptionally cold winter that might occur once every ten years.

This paper focuses on average and peak demand. In addition, a commentary is provided on ‘one in ten’ demand. The paper primarily focuses on electricity. There are major issues in respect of gas supply which would require a separate paper. In this paper, they are considered in terms of their effect on electricity supply, since 35 per cent of our electricity is generated by using gas.

The electricity we use is primarily supplied by large scale generation plant. Over the course of the year these are not fully available - their output is limited by routine maintenance and unplanned problems. This paper assumes average plant availability is 65 per cent. The detailed figures for each different type of generation are based on DUKES [15]. Generators make strenuous efforts to ensure plant is available at peak times. We have hence assumed peak availability is 90 per cent. This is broadly consistent with history - for example in the winter of 2004/5 NGT estimate 5-6 GW, about 9 per cent of plant, was unavailable. [18]

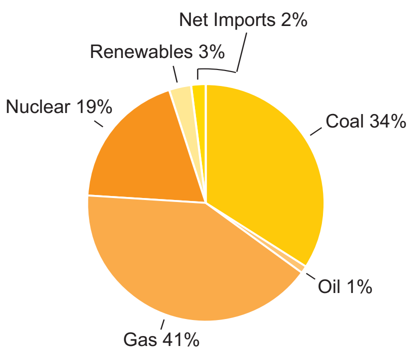



Figure 1:
**Electricity supply mix 2004**

## 2.2 Current UK Supply

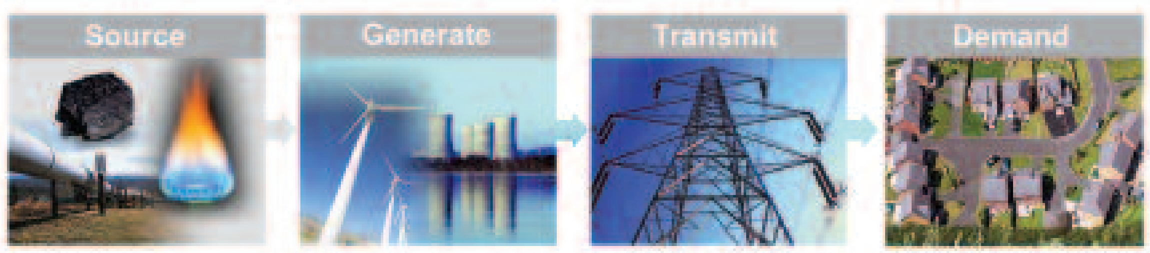
Compared with many other countries, the range of electricity source and generation capacity in Britain is diverse, as shown in Figure 1 [3] which gives the percentages of electricity generated from each type of plant in 2004.
The predominant sources are: [2]

- Gas - 25GW capacity: Historically this has been largely sourced from the North Sea and burnt in Combined Cycle Gas Turbine (CCGT) plant
- Coal and Oil - 31GW capacity: This is sourced both from the UK and imports
- Nuclear - 12GW capacity
- CHP & Renewables: 7GW capacity
- Interconnector: 2GW of capacity import of electricity from France.

The nature of this mix has changed significantly in recent years, with a massive increase in the amount of gas-fired generation coinciding with a decline in the proportion of coal-fired and nuclear generation.  This is a trend which is expected to continue.

## 2.3 What is causing the gap?

The gap is arising because of a range of factors right across the energy chain:




**Source:** We currently source about 75 per cent of our primary energy ourselves. [20] This will drop to about 20 per cent by 2020. The UK has been self sufficient in **gas** since the 1970's, but in future most of our gas will come from countries such as Russia, Algeria and Norway. Our **coal** imports have increased from 31 per cent to 59 per cent of our needs since 1997. [20]

**Generation:** [1] [2] [8] We will lose about 50 per cent of our existing generation capacity by 2020. The nuclear fleet is ageing and all bar one station will close by 2020. Coal stations will either need to be upgraded to meet stringent EU requirements or close; about 50 per cent will close by 2015. **Coal** is also a major producer of $CO_2$ and we need to reduce consumption to meet our Kyoto commitments.

**Transmission:** There are exciting opportunities with new renewable energy sources. However, our energy infrastructure, 'the wires' do not support this. The vast majority of wind and wave power is in Scotland and more than £1bn investment is required to bring this South.  An equally significant issue is that planning permission will need to be achieved in the face of concerted opposition.

**Demand:** Demand increases every year as people and businesses use energy intensive devices. These figures have been rising steadily at over 1 per cent per annum for a number of years, and current forecasts expect that demand will continue to rise by between 1.3 per cent and 2.4 per cent per annum between now and 2020. [2]

1 This paper primarily discusses the situation in Great Britain since this is the basis on which most data is published. Northern Ireland has comparable issues, and the development of the All Island Project makes it most likely that the situation in Northern Ireland will be addressed jointly with that in the Irish Republic.

2 See appendix A for an explanation of electricity measurement.

# Filling the gap Options and Risks

### 2.4 How could we fill the gap?

There are a range of options open to the UK to fill the energy gap. Each of these has the potential to contribute to filling the gap, each has advantages and each has risks.

The table opposite sets out the broad opportunities and the risks that may prevent them fulfilling their potential. This is the used as the basis for the scenario analysis.

| Area | Primary Opportunities |
|---|---|
| **Demand** | The Building Research Establishment estimates household energy usage could be reduced by 46 per cent with efficiency measures. [21]<br>Industry similarly has efficiency opportunities.<br>Price rises are driving interest in energy efficiency. |
| **Source**<br>Gas | New Norwegian pipeline onstream in 2006, capable of delivering 14m therms per day (pd). [4]<br>Expansion of the Bacton gas interconnector to 24m therms pd.[4]<br>Development of further Liquefied Natural Gas (LNG) terminals.<br>Development of additional gas storage for the UK. |
| **Generation**<br>Nuclear | Government approves nuclear build and stations, which can now be developed in 4-5 years, start to come on stream by 2016. |
| Coal | Clean coal technology significantly reduces $CO_2$ emissions and enables greater investment in coal power stations. |
| Gas | Substantial gas plant constructed to use new gas supplies - 9.7GW currently planned. [2] |
| CHP/Renewables | 8.2 GW of renewables constructed to plan. [2] |
| **Interconnectors** | 800MW of capacity added from the Netherlands interconnector.[2] |
| **Transmission & Distribution** | No additional requirements for transmission to cater for new renewables. |
| **Cost and Build** | |


| Primary Risks |
| --- |
| Demand increases greater than expected due to economic growth.<br>Demand increases due to our increasing electronic/digital lifestyle.<br>Capital outlay inhibits take up of efficiency opportunities. |
| Gas is not available through the Bacton interconnector due to problems with the supply from Russia.<br>Gas is not available due to excessive demand on Continental Europe.<br>LNG diverted to other countries offering higher prices.<br>Storage delayed due to planning problems. |
| Current ageing plant experiences increasing problems and downtime.<br>Lack of clear conclusions from the Energy Review delays nuclear build.<br>Escalating cost of waste disposal delays new nuclear build.<br>Planning approval requirements delay new build.<br>Global demand for uranium soars on increased demand from India and China, restricting supply. |
| Current ageing plant experiences increasing problems and downtime.<br>Global demand for coal soars restricting supply. |
| Planning approval requirements delay new build.<br>Reluctance to build because of uncertainty over gas supply. |
| Lack of clear conclusion from Energy Review delays investment.<br>Concerns over cost of renewable energy delay investment.<br>Wind power not available on the coldest days.<br>Market rules do not encourage CHP/renewables. |
| Problems with availability (see source - gas above). |
| Disagreements over transmission funding and planning delay build.<br>Planning approval requirements delay new build. |
| Overall cost and build effort is prohibitive leading to delays.<br>Costs of up to £54bn have been estimated. [22] |

# 3. Scenarios

## 3.1 Introduction to Scenario Development

This paper develops ‘optimistic’ and ‘conservative’ scenarios in order to identify the scale of the energy gap and when it may occur.

**Optimistic Case:** These take a set of ‘optimistic’ assumptions and map them to average and peak demand for the periods 2005 - 2010; 2010 - 2015 and 2015 - 2020.

**Conservative Case:** These examine issues and problems that may create barriers to changes in our energy supply and hence develop a set of more ‘conservative’ assumptions and map them to average and peak demand for the same periods.

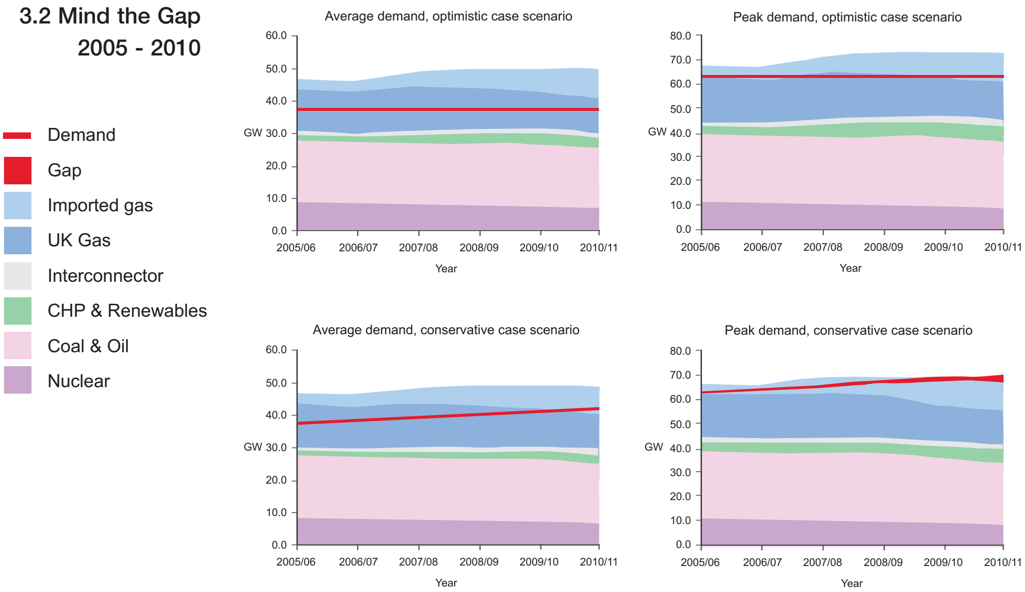
There are obviously a huge range of potential scenarios. These scenarios aim to represent a 75 percentile and 25 percentile view of likelihood.

The graphs show the availability of different types of generation according to the legend shown to their left.

Contingency is represented by energy supply above the red demand line. Historically a planning contingency of 24 per cent was used. For short term planning a margin of 10 per cent is typically used given the greater certainty. [2]

The ‘gap’ is represented by the red shaded area between the imported gas supply area and the red demand line.

## 3.2 Mind the Gap 2005 - 2010



### 3.2.1 Summary - the position in 2010

The scenario is broadly based on current planned infrastructure being implemented. In particular the Langeleld pipeline to Norway should be completed and provide a significant boost to our gas supply next year. Given the relatively short timescale, there should not be problems with the planned infrastructure. Furthermore, the nuclear shutdowns will have had limited impact, hence overall the scenario is relatively benign. This could change rapidly if there are unplanned problems with the nuclear fleet.

#### Optimistic Case

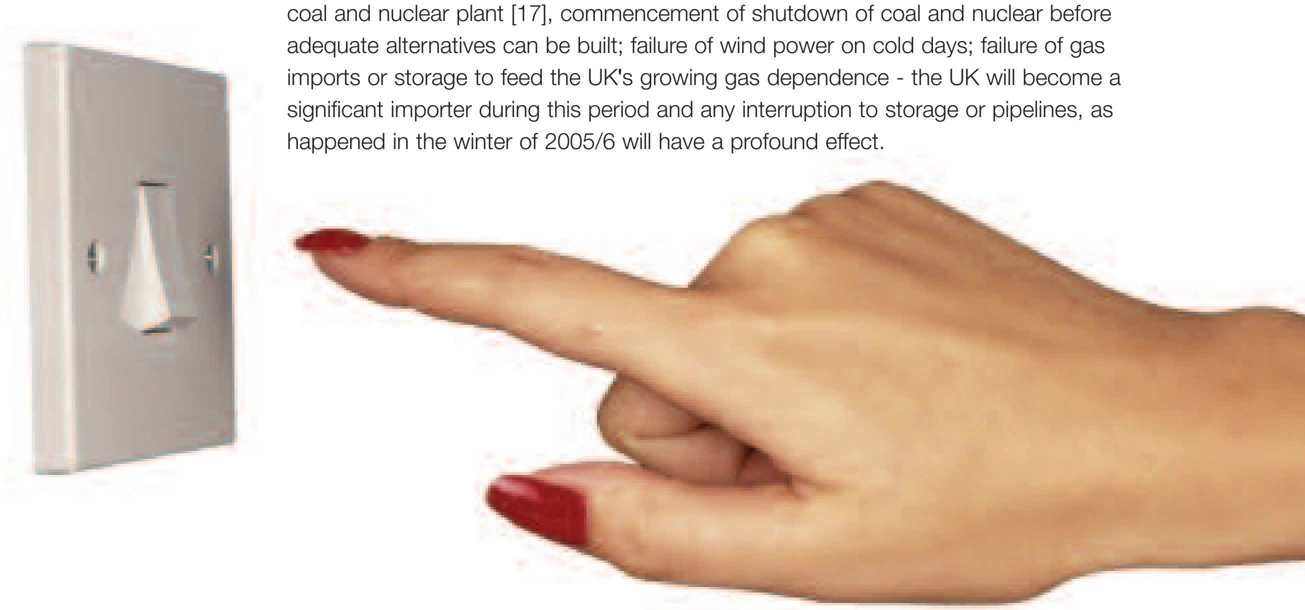
There should be no risk to the UK energy supply based on this scenario. There is a healthy 33 per cent contingency at average demand and an adequate 15.5 per cent contingency at peak demand.

#### Conservative Case

There is little risk to average demand with 17 per cent contingency even in the conservative case.

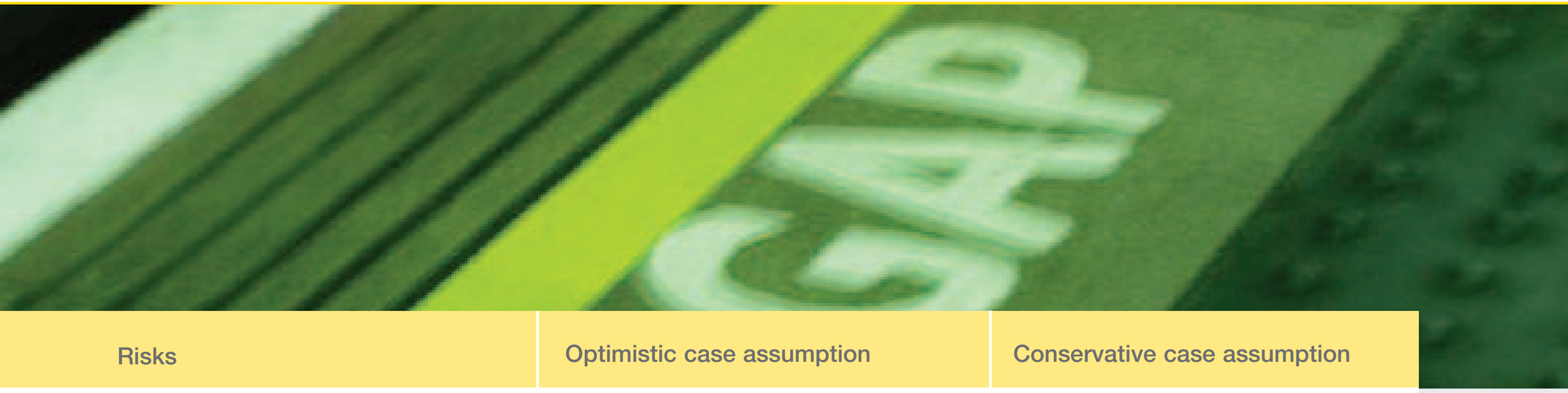
There is a serious risk to peak demand. The scenario indicates a gap of 4.6 per cent demand in the winter of 2010/11 with no contingency. This is equivalent to the whole of Wales losing supply for several days in winter. Moreover, within this situation there is no contingency therefore the gap could be around 15 per cent. This would drive a significant percentage of residences and businesses off supply - equivalent to the great storm of 1987.

The key issues that could drive the conservative case are: increasing failures of ageing coal and nuclear plant [17], commencement of shutdown of coal and nuclear before adequate alternatives can be built; failure of wind power on cold days; failure of gas imports or storage to feed the UK's growing gas dependence - the UK will become a significant importer during this period and any interruption to storage or pipelines, as happened in the winter of 2005/6 will have a profound effect.



## 2010 Scenario Assumptions

| Area | Changes in energy provision |
|---|---|
| **Demand** | |
| **Source**<br>Gas | New Norwegian pipeline onstream in 2006.<br>Expansion of the Belgian gas interconnector. |
| **Generation**<br>Nuclear | 2.3 GW of nuclear plant closes. [2]<br>No new build in this timeframe. |
| Coal | 1 GW of coal plant closes. [8]<br>No new build in this timeframe. |
| Gas | 5 GW of gas plant constructed to use new gas supplies. [2] |
| Renewables | 6.2 GW of renewables constructed to plan. [2] |
| **Electricity Interconnectors** | 800 MW of capacity added from the Netherlands interconnector. [2] |
| **Transmission & Distribution** | Additional requirements for transmission to support renewables. |




| Risks | Optimistic case assumption | Conservative case assumption |
|---|---|---|
| Demand increases greater than expected due to economic growth and digital lifestyle.<br>Efficiency improvements do not keep pace with historic achievement. | No demand growth (i.e. growth of 1.3 per cent from economic growth is balanced by efficiency gains). [derived from 2] | Demand grows at 2.4 per cent pa. [derived from 2] |
| Gas is not available through the Belgian interconnector due to problems with the supply from Russia. | 100 per cent of gas required for generation is available. | Only 85 per cent of gas required for generation is available. |
| Availability decreases as plant ages with increasing planned and unplanned downtime. | 2.3 GW closure.<br>90 per cent availability. | 2.3 GW closure.<br>Only 85 per cent availability due to problems with ageing plant. |
| Availability decreases as plant ages with increasing planned and unplanned downtime. | 1 GW of plant closes. | 1 GW of plant closes.<br>Only 85 per cent availability due to problems with ageing plant. |
| Delays in gas construction.<br>Not enough gas to run generation. | 5 GW of new plant available. | 5 GW of new plant available. |
| Wind power not available on the coldest days. | 13 GW of renewable generation available. | Slow down in build due to lack of transmission.<br>Limited availability due to lack of wind. |
| Capacity not built to schedule.<br>Capacity not available due to high continental demand. | Full capacity. | Interconnector runs at only 75 per cent capacity as energy diverted to the continent. |
| No risk in this period. | Transmission development not required in this period. | Slow transmission approval delays renewable uptake. |

**2010 - Is this conservative case realistic?**

It is an icy cold winter's day across the UK and much of the European continent. The long-awaited '1 in 10' winter has finally arrived and children are playing in the snow. Sian Lloyd is advising us that the current anti-cyclone which has been settled over the UK for the last two weeks looks like it is here for at least another week.

Energy demand across the UK increases by 5 per cent compared with normal levels of demand for the time of year as people turn up the heating and stay inside, driving up usage of a range of appliances.

The UK has made substantial progress in developing wind turbines to produce clean efficient energy, but across the UK these stand stationary as the anti-cyclone means there is no wind whatsoever. This is exacerbated by delayed build of transmission due to planning problems and limited funds approval.

Across Continental Europe the demand for gas soars as people heat their homes and major European countries such as Germany, Italy and Spain, who rejected nuclear energy and use large amounts of gas for generation, drive their generation plant at peak load. As a result of this, the gas interconnector to the UK runs at only 50 per cent of its potential capacity. National Grid issues warnings and interrupts gas to industry to maintain the domestic supply.

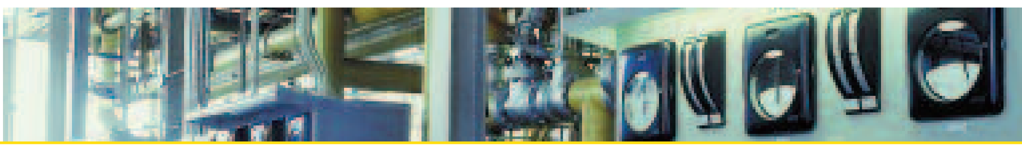
Electricity interconnection from both France and The Netherlands is reduced as those countries struggle to support their own demands.

Ageing nuclear and coal plant, which is due to be decommissioned in the next two years anyway, starts to experience unplanned failures as it has been running non-stop during the last two weeks of the anti-cyclone.

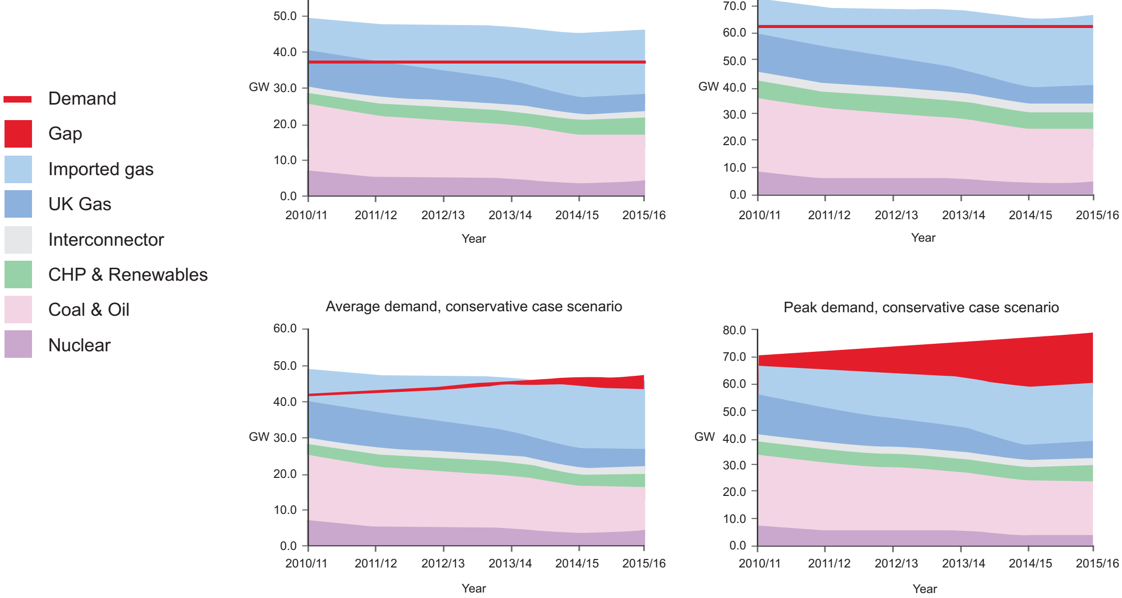
As a result of the loss of 5 GW of capacity, energy supply is no longer able to meet demand and the lights go out across an area equivalent to the size of Wales.

All these events are plausible and indeed many have already occurred. In many ways the events feed each other - for example anticyclones will drive peak demand and will negate the use of wind. This is a serious option for the Energy Review to consider.

“ ... energy supply is no longer able to meet demand and the lights go out across an area equivalent to the size of Wales. ”



## 3.3 Mind the Gap 2010 - 2015




### 3.3.1 Summary - the position in 2015

The key issue is that at least 10 GW of coal plant and 7 GW of nuclear plant will have closed. [2] [8] This is coupled with the increasing dependence of the UK on imported gas during this period. The scenario primarily assumes that gas plant will be built since it is extremely unlikely that it will be possible to build nuclear plant in this timescale. [16]

#### Optimistic Case

At peak demand there is only a 3.8 per cent contingency. This is well below historic best practice and raises significant risks of limited power outages.

At average demand levels there is a minimum of 21 per cent contingency   just about adequate in accordance with traditional planning levels.

#### Conservative Case

In the conservative case there are very major deficiencies to the UK energy supply. At average demand there is a gap of 9 per cent, equivalent to Eastern England losing supply.  At peak there is a gap of 23 per cent - this is a substantial shortfall and equivalent to the whole of London and the South East losing supply for several days over the winter.  These kind of figures raise the spectre of a 3 day week and energy rationing.

# 2015 Scenario Assumptions

The main issue is the substantial loss of generation plant, both nuclear and coal to 2015: 10 GW of coal plant and 17 GW of nuclear plant will have closed, but it may not have been possible to build significant alternatives other than gas.

Nuclear plant is unlikely to be built in this timescale. Renewables may not be built because of uncertainty over their role if the Energy Review throws its weight behind nuclear or because of planning delays. Renewables will also require significant transmission upgrades- these are still under discussion between NGT and Ofgem. On June 26th 2006, the UK press reported that Ofgem had signalled it may only approve half of National Grid's request for transmission upgrade money. Further, the majority of planned renewables is wind, which is, by definition, highly susceptible to the weather and may not function on cold days.

The key issue will again be the UK's gas import dependence with very high disruption as the result of any problems.

| Area | Changes in energy provision |
|---|---|
| **Demand** | |
| **Source**<br>Gas | New pipelines to support expansion in gas generation.<br>Development of gas storage to give the UK greater reserves. |
| **Generation**<br>Nuclear | 7.1 GW of nuclear plant closed sine 2006. [2] |
| Coal | 10 GW coal plant closes by 2015 due to EU Large Combustion Plant Directive (LCPD) regulations. [2] [8]<br>No new build in this timeframe. |
| Gas | Further construction at 1 GW pa. [derived from 2] |
| Renewables | Further construction at 1 GW pa. [derived from2] |
| **Electricity Interconnectors** | 500 MW of capacity added from the Netherlands interconnector. [2] |
| **Transmission & Distribution** | Major requirements for transmission to meet renewables. |


| Risks | Optimistic case assumption | Conservative case assumption |
|---|---|---|
| Demand increases greater than expected due to economic growth and digital lifestyle.<br>Efficiency improvements do not keep pace with historic achievement. | No demand growth (i.e. growth of 1.3 per cent from economic growth is balanced by efficiency gains). [derived from 2] | Demand grows at 2.4 per cent pa. [derived from 2] |
| Gas is not available due to supply problems from Russia.<br>Gas storage slow to become available due to planning problems. | 100 per cent of gas required for generation is available. | Only 85 per cent of gas required for generation is available. |
| Downtime increases as plant ages.<br>No new build because: no clear mandate from policy review; planning problems; decommissioning overruns; build overruns. | Availability at 90 per cent. | 7.1 GW closure.<br>Only 85 per cent availability due to problems with ageing plant.<br>No new build available. |
| Downtime increases as plant ages.<br>New build restricted by planning problems; no clear mandate. | Availability at 90 per cent. | 10 GW of plant closes.<br>Only 85 per cent availability due to problems with ageing plant. |
| Delays in gas construction.<br>Not enough gas to run generation. | 10 GW of new plant available.<br>35 GW total. | Delays to 3 GW of plant due to planning or development problems. |
| Wind availability on coldest days.<br>No clear mandate from energy review restricts investment. | 17 GW of renewable generation available. | Slow down in build due to lack of transmission.<br>Limited availability due to lack of wind. |
| | Full capacity available. | Interconnector runs at only 75 per cent capacity as energy diverted to the continent. |
| | Required transmission fully available. | Slow transmission approval delays renewable uptake. |

**2015 - Is this conservative case realistic?**

The justification for this scenario is almost exactly the same as that painted for the 2010 scenario, but it is made much worse by the fact that there have been considerable plant closures since 2010. 7.1 GW of nuclear capacity and up to 10 GW of coal and oil capacity, about 20 per cent of current capacity, will have closed. New build will almost certainly not keep pace given that there is as yet no clear policy decision and new build will need to go through a substantive planning process.

This has left the UK highly dependent on gas. However, by this period the UK will only be able to supply about 25 per cent of the gas it requires. [1] [3] There are many encouraging signs on gas imports, in particular the signing of long term contracts with Norway for gas across the Langeled pipeline. There are also developments to import LNG.

However, this still leaves the UK highly vulnerable to a range of events:

- Uncertainty of Russian gas supplies. There is a continuing debate about the dependence of the EU and UK on Russian gas supplies. This was fuelled by Russia's decision to quadruple prices to the Ukraine in January 2006. It should be noted that Russia has supplied gas all through the cold war and that Ukraine was receiving gas at well below market price, but the political dimension will inevitably remain. Of equal importance is the fact that there are competing markets for Russian gas. Europe is not Russia's only market. The burgeoning economies of Indian and China will provide a very attractive alternative market for Russian energy.

- Continental European growth. The UK is at the end of a very very long pipeline, with many hungry energy users in between. In the winter of 2005, we have already seen the gas interconnector to The Netherlands running at well below peak capacity while UK prices soared. With European countries declaring no nuclear energy policies, European demand for gas can only increase. At the same time last winter, the electricity interconnector to France also ran at only 50 per cent of capacity for periods while energy was diverted to fulfil local needs.

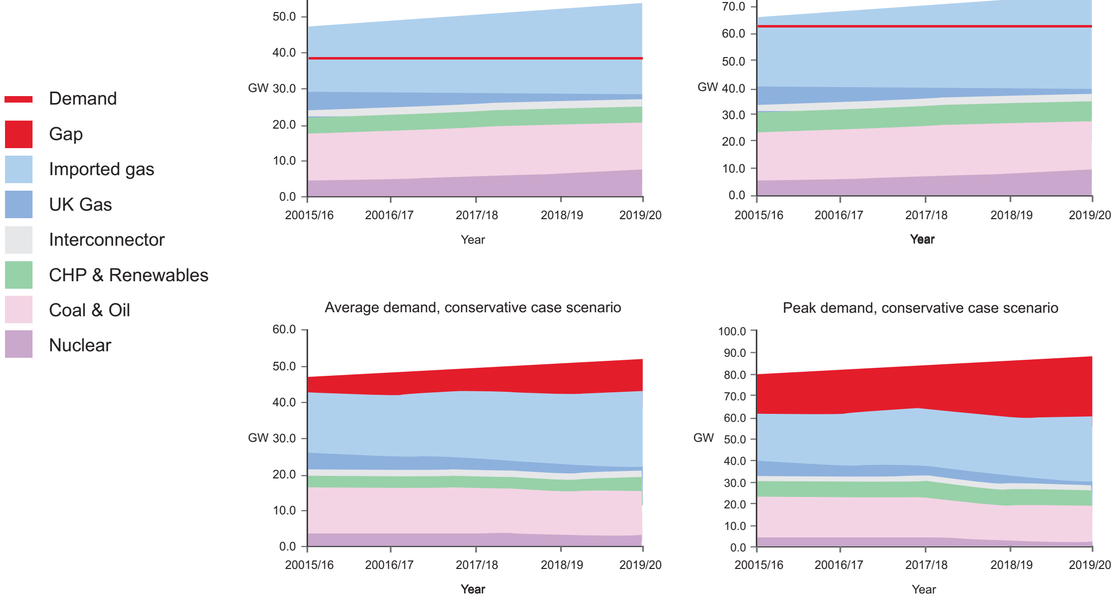
- Corporate uncertainty in the UK. UK companies have signed up to contracts for Norwegian gas. This creates important diversity of supply. However, these companies are subject to takeover, with the risk that contracts may be moved to other regions of supply.

- LNG economic uncertainty: LNG is a highly transportable commodity - subject to contract it will go where the price is highest. Again, in the winter of 2005, we have already seen LNG supplies diverted from the UK to seek higher prices.

- Lack of storage. The UK can store only about 4 per cent of its gas needs, this compares to about 20 per cent in France and Germany. [derived from 4] Storage development is a critical requirement, but in the current year, major storage developments have been dropped because of planning problems.

All these events are highly plausible and again many have already occurred, even though it is only 2006 and this scenario is trying to look ahead to 2015. This is a serious option for the Energy Review to consider.

## 3.4 Mind the Gap 2015 - 2020




### 3.4.1 Summary - the position in 2020

This is 15 years beyond the present day and, even allowing for the long term planning cycle of major generation plant, there should be sufficient opportunity to fill the gap. The greatest risks will be whether the chosen strategy proposed by the Energy Review is adhered to, or whether a change of government or world or economic events derail it. There will also almost certainly be a residual risk of UK dependence on imported gas, unless the government undertakes a dramatic change in strategy.

#### Optimistic Case

The optimistic case, based on on-time delivery of nuclear build, a significant expansion of gas and continued development of renewables, provides an adequate 16.7 per cent contingency at peak demand and a healthy 41 per cent contingency at average demand.

#### Conservative Case

In the conservative case there are very major deficiencies to the UK energy supply. At average demand there is a gap of 16 per cent and at peak a gap of 31.5 per cent. The primary driver behind such a gap would be a significant change of strategy. In the scenario, we have considered what could happen if a nuclear strategy was adopted, but then not followed due to changing events. We would emphasise this type of scenario is not limited to nuclear. For example, if the review adopts a very strong renewable strategy, but this is unsuccessful, there would be insufficient time to build nuclear or coal plant.

## 2020 Scenario Assumptions

| Area | Changes in energy provision |
|---|---|
| **Demand** | |
| **Source**<br>Gas | New pipelines to support expansion in gas generation. Development of gas storage to give the UK greater reserve contingency. |
| **Generation**<br>Nuclear | 8.2 GW of nuclear plant closed sine 2006. [derived from 2] |
| Coal | |
| Gas | Further construction at 1 GW pa. [derived from 2] |
| Renewables | Further construction at 1 GW pa. [derived from 2] |
| **Electricity Interconnectors** | No further additional interconnection. |
| **Transmission & Distribution** | Major transmission developments to support renewables. |


| Risks | Optimistic case assumption | Conservative case assumption |
|---|---|---|
| Demand increases greater than expected due to economic growth and digital lifestyle.<br>Efficiency improvements do not keep pace with historic achievement. | No demand growth (i.e. growth of 1.3 per cent from economic growth is balanced by efficiency gains). [derived from 2] | Demand grows at 2.4 per cent pa. [derived from 2] |
| Gas is not available due to supply problems from Russia.<br>Gas storage slow to become available due to planning problems. | 100 per cent of gas required for generation is available. | Only 85 per cent of gas required for generation is available. |
| Downtime increases as plant ages.<br>No new build because of: no clear mandate from policy review; planning problems; decommissioning overruns; build overruns. | Availability at 90 per cent on worst days.<br>New construction at 1 GW pa since 2015. | 8.8 GW closure.<br>Only 85 per cent availability due to problems with ageing plant, declining to 80 per cent in 2019.<br>No new build available. |
| Downtime increases as plant ages.<br>New build restricted by planning problems; no clear mandate. | Availability at 90 per cent on worst days. | 10 GW of plant closes.<br>Availability 85/80 per cent as for nuclear. |
| Delays in gas construction. | A further 5 GW of new plant available.<br>40 GW total. | Delays to 5 GW of plant due to planning problems or reluctance to invest. |
| Wind availability on coldest days.<br>No clear mandate from energy review restricts investment. | 21 GW of renewable generation available. | Slow down in build due to lack of transmission.<br>Limited availability due to lack of wind. |
| | Full capacity available. | Interconnector runs at only 75 per cent capacity as energy diverted to the continent. |
| | Required transmission fully available. | Slow transmission approval delays renewable uptake. |

**Is this conservative case scenario realistic?**

Consider the following possible sequence of events between now and 2020:

The Government's Energy Review is published in July 2006. It recommends a sensible strategy to tackle the energy gap on every front possible. This includes:

- Energy efficiency measures
- Framework for renewable investment
- Framework for local generation (for example, domestic combined heat and power)
- Commitment to clean coal
- Nuclear new build

Nuclear generation is seen as the only viable way of replacing the substantial losses from coal and nuclear closures while reducing emissions. The increasing stability and strength of the UK nuclear sector is recognised and European countries, particularly EDF from France, agree co-operation.

However, during the initial stages of the nuclear planning process, there is a change of Labour leadership or change of government. A nuclear sceptic prime minister takes the post. General nuclear scepticism grows fuelled by:

- Dramatically escalating costs in the decommissioning programme, rising from an original £57bn to £120bn
- Delays in decommissioning, which means new power stations cannot be built on old sites until they are clear. Therefore build is either delayed or has to take place on new sites, with significant problems around planning.
- Delays in the build itself as companies experience the kind of problems common in major construction projects such as Wembley and the Scottish Parliament.
- Problems with waste disposal as The Irish government wins a case in the European court over potential impact of waste from Sellafield on the Irish Sea.
- Problems with the supply of Uranium. In 2006 some comments estimate there could only be 50 years supply of Uranium left at current rates of usage. [commentary in 16] However, during this period the Chinese and Indian economies continue their amazing growth and nuclear power is a key source for them. This drives up the price of Uranium and restricts supply.
- Lack of qualified UK resources as most of the knowledgeable population retire. Although France provides assistance, many of their engineers are also retiring and are drawn to large salaries being offered in Eastern countries.

During this period, there is also at least one change of government. The new government broadly follows the nuclear strategy, as there is no other immediate option, but given the above problems curtails development and moves to a new strategy, incurring further delays.

All these events are highly plausible. For example, nuclear decommissioning was costed at £56bn at the time of the Energy Act of 2004, by 2006 it has already risen to £70-90bn. This is a serious option for the Energy Review to consider.

# Appendices

## Appendix A

### Energy Measurement

The basic unit of electric power is the watt (**W**) - domestic electrical equipment is typically rated in terms of the number of watts which they consume - e.g. a 100W light bulb or a 1000W electric fire. The power output of larger appliances is usually measured in kilowatts (**kW**), where 1kW equals 1000W.

The basic unit of electric energy is the watt-hour, which is the amount of energy consumed if a 1W appliance runs for one hour. Energy consumption in the home is normally measured in kilowatt-hours (**kWh**). Leaving a 100W light bulb on for ten hours consumes 1 kWh.

A typical domestic property is now estimated to consume around 4700 kWh each year. Overall domestic energy consumption has increased by 32 per cent since 1970 and by 19 per cent since 1990. However, since 1990 the number of households has increased by 10 per cent, with the consumption per household actually falling slightly.

The output from a power station is usually given in megawatts (**MW**), though smaller stations may be rated in kW. 1MW equals 1000kW; 1MWh equals 1000kWh. The most modern nuclear power stations typically have a capacity of around 1200 MW; the UK's largest coal-fired power station, at Drax in Yorkshire, has a capacity of 4000 MW, or 4 gigawatts (**GW**); 1GW equals 1000MW, and 1GWh equals 1000MWh.

Finally, overall annual consumption across the country is measured in gigawatt hours or terawatt-hours (**TWh**); where 1TW equals 1000GW and 1TWh equals 1000GWh. Overall **average consumption per day is 39 GW, per annum is 355TWh**. [derived from2 and 23]

To summarise the units:

1000W = 1kW
1000kW = 1MW
1000MW = 1GW
1000GW = 1TW

Table 1:
**Conversions between energy units**

The conversion table, based on information from National Grid's Gas Ten Year Statement [4], may also be useful. To convert from the units on the left hand side to the units across the top multiply by the values in the table:

| To: From: (below) | GWh | Million cubic metres (mcm) | Million therms | Thousand tonnes of oil equivalent (toe) |
|---|---|---|---|---|
| GWh | X | 0.092 | 0.034 | 0.086 |
| Million cubic metres (mcm) | 10.833 | X | 0.370 | 0.932 |
| Million Therms | 29.307 | 2.710 | X | 2.520 |
| Thousand tonnes of oil equivalent (toe) | 11.630 | 1.073 | 0.397 | X |

Note: all volume to energy conversions assume a Calorific Value of 39 $MJ/m^3$

## Appendix B Energy Demand

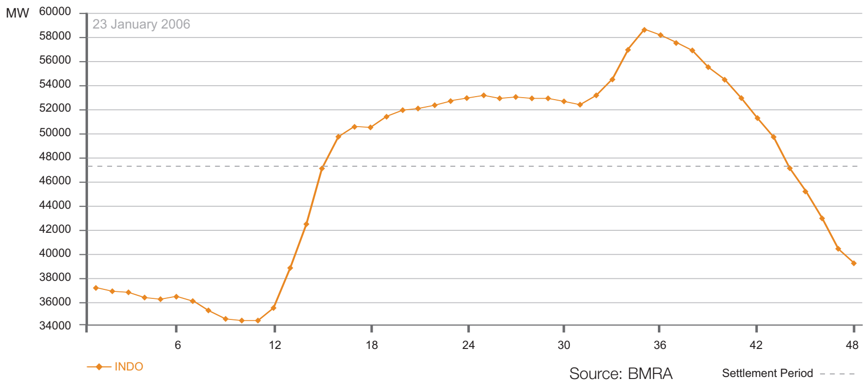
### B1 - Current Energy Demand

The overall consumption of electricity in Great Britain is usually given in GW. For the purposes of sizing the gap, we have considered average demand and peak demand. We have also provided some commentary on the concept of a ‘1 in 10’ winter.

Electricity consumption is currently running at an average of around 39 GW. This figure increases by about 3 GW in the winter and decreases by around 3 GW in the summer. [derived from 23]

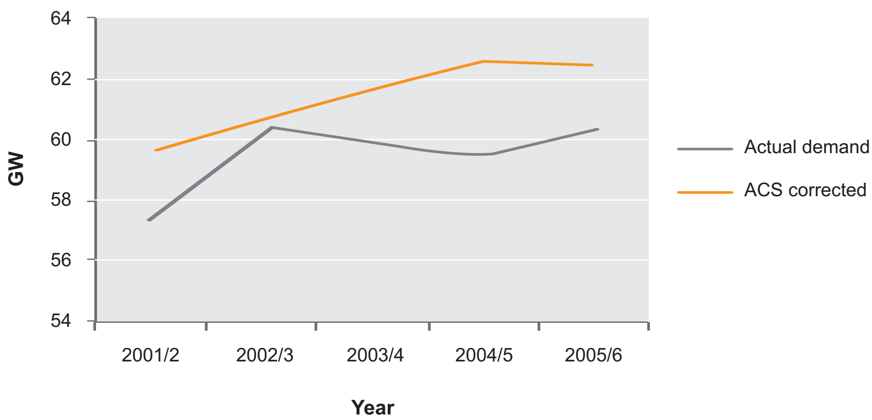
Within a given day, and from day to day (and especially between weekdays and weekend days), demand can vary substantially from a low or base demand of around 30GW, to a high or peak demand of around 50GW. [derived from 23] The pattern of demand variation shown in Figure 2 below is for a recent winter weekday, and is broadly typical:

Figure 2:
**Typical daily demand curve**




The maximum demand recorded in Great Britain to date is 61.6 GW in the winter of 2003/4. [2] Many factors influence the level of peak demand, of which one of the most important is the weather. For this reason National Grid invariably adjust peak demand figures to a standard ‘Average Cold Spell’ (ACS), which is defined as the level of peak demand that has a 50 per cent chance of being exceeded as a result of weather variation alone. Peak and ACS demand is shown in figure 3. [2]

Figure 3:
**Peak electricity demand**



The most recent data continues a trend which has been apparent for some years, of a steady increase in the demand for electricity of something in excess of 1 per cent per annum. This is true of both the key measures of electricity demand used by National Grid; the level of demand at the annual peak, and the total overall annual consumption.

Average daily gas consumption in Great Britain is of the order of 250 million cubic meters per day, with peak daily gas consumption of c. 540 million cubic metres (mcm) per day according to the National Grid's Gas Ten Year Statement. [4]

This figure has recently been rising steadily from year to year at a rate in excess of 2 per cent per annum. By comparison, over the previous ten years, the average growth rate was 5.5 per cent per annum. The main source of the increase - as it has been for a number of years - is the construction of additional Combined Cycle Gas Turbine (CCGT) power stations in order to meet the growth in demand for electricity and replace the power stations which close. Although the so-called 'dash for gas' has slowed in recent years, it remains the most significant factor in the rate of increase of gas usage.

Gas and electricity consumption are inextricably linked, with one-third of all the gas consumed being used to generate electricity. The proportion of Britain's electricity generated from gas will almost certainly continue to rise in the coming years - thus any gap in the availability of gas will have a disproportionate effect on the overall energy gap.

### B2 - Forecasts of future demand

Forecasts of future change in demand are dependent on a complex range of variables, from the rate of economic growth to changes in fuel prices. To give an indication of the level of complexity involved, one key paper from the DTI [5] is based on a model "...which comprised some 130 econometric equations of which approximately 60 were fuel share equations, 20 were stock equations and the remaining 50 were energy demand equations."

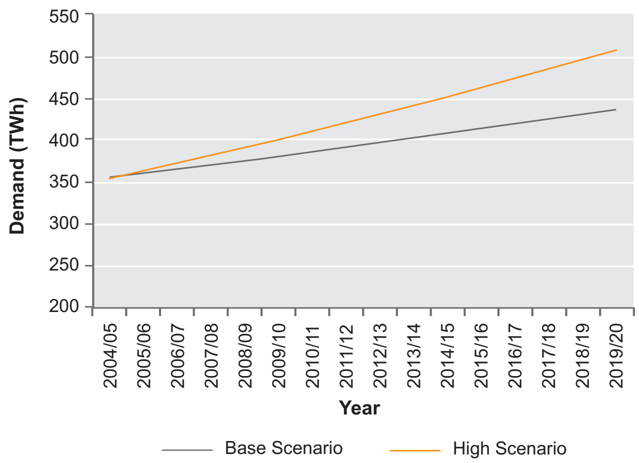
We have based our estimates of future demand on some of the most widely respected used figures available. Each year National Grid, in its capacity as the Great Britain System Operator, produces a wide range of forecast information relating to the electricity transmission system in Great Britain, including forecasts of the demand for electricity over the next seven years. This document is accordingly known as the Seven Year Statement (SYS) [2]. We have taken the latest available forecasts, covering the years 2006 to 2013, from the 2005 and 2006 SYS documents; and have extrapolated these through to 2020, based on the same underlying assumptions but with some modifications.

### Electricity demand

In the 'base' scenario as envisaged by National Grid, over the next seven years (2006 - 2013) total annual electricity demand is projected to increase by an average of 1.3 per cent per annum. This is based on an economic forecast which assumes an average growth in GDP of 2.7 per cent per annum. This is also in line with the latest projections in the Chancellor of the Exchequer's Budget forecasts of 22 March 2006, in which he predicted a growth rate of 2.75 per cent per annum for 2007-2008. Thus the 'base' scenario figures in Figure 4 below, can be taken as a reasonable estimate of the likely growth in electricity consumption.

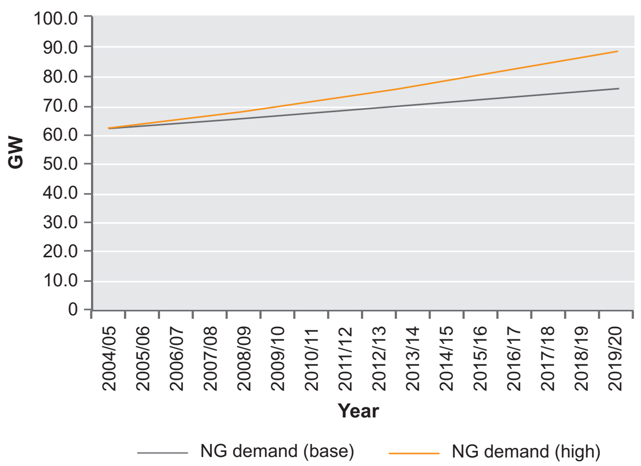
In our scenario modelling we have also considered the 'high' demand case forecast by National Grid, in which economic growth of 3.1 per cent per annum gives rise to an average increase in demand for electricity of 2.2 per cent per annum. This rate of growth is slightly lower than the Chancellor's Budget forecast of a maximum of 3.25 per cent per annum growth in GDP, so we have adjusted NGT's figures in line with the Chancellor's forecast. These give rise to a steady average increase in the consumption of electricity, adjusted for ACS corrections, of 2.4 per cent per annum, as shown below:

Figure 4:
**Forecast electricity demand**




Adjusting National Grid's forecasts for peak demand in the same way, gives the following:

Figure 5:
**Forecast peak electricity demand**

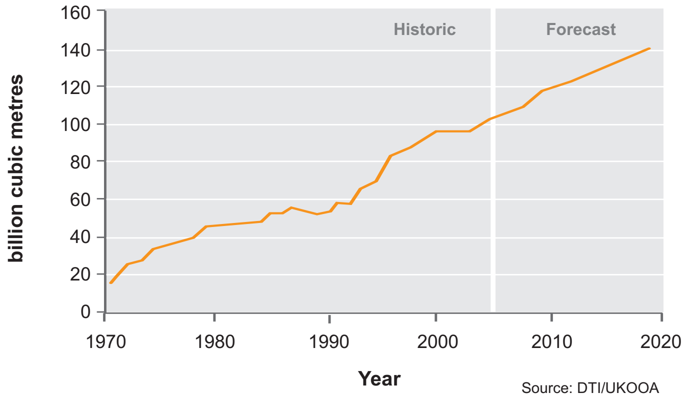


These forecasts are adjusted to include ACS corrections - though what is very difficult to assess is how much these figures might be uplifted in an exceptionally cold winter. In 2002/03, for example, the actual peak in demand was 1 per cent higher than the ACS corrected figure - but 2002/03 was one of a series of exceptionally mild winters. It is conceivable that in an exceptionally cold spell, demand could rise by as much as 10 per cent compared with ACS corrected figures - and we have used this as an illustrative figure in our scenario modelling.

## Gas demand

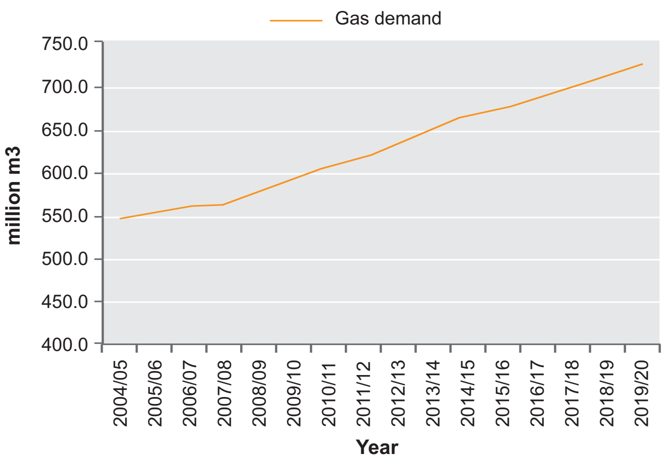
The rates of growth in the demand forecast for gas are broadly comparable with those forecast for electricity. For example, the UK Offshore Operators Association (UKOOA) [3] forecasts a growth in annual consumption from around 95 billion $m^3$ in 2004 to around 140 billion $m^3$ in 2020 - a growth rate of around 2.6 per cent annum, as shown in Figure 6 below.

Figure 6:
**UK gas consumption 1970 - 2020**




Similarly the analogous measure to peak electricity demand, the peak day gas demand, is projected to grow at a comparable rate to that in the 'high' demand scenario for electricity, i.e. by some 30 per cent over the next 15 years, as shown in Figure 7 [4]:

Figure 7:
**Peak day gas demand**



**Factors influencing demand**

The analysis (previous page) links demand growth to economic growth and adjusts that to include historic demand efficiency achievements. There are other factors that may drive growth up or down, for example:

Demand Increases

- Energy intensive lifestyle: The availability of technology to provide consumer satisfaction has been a driver of energy demand for decades. New advances, or widespread increases in availability of new technologies, could fuel disproportionate demand increases. Possible examples include the use of air conditioning which - ironically - will almost certainly grow with global warming in the UK; and a widespread digital lifestyle.
- The decline in UK manufacturing, which has helped drive reductions in energy usage over the last decades is arrested. For example, the NGT's forecasts of the growth in demand for electricity are based on expectations of an increase in manufacturing output of around 2 per cent per annum.

Demand Decreases

- Escalation in energy prices drives greater interest and uptake of efficiency for both businesses and consumers.
- Government introduces more stringent efficiency requirements and incentives to help drive down our $CO_2$ usage and meet their commitments under international agreements such as the Kyoto Protocol.
- Innovative technology improves efficiency of energy usage - for example, appliances on standby consume much less energy than at present (for existing appliances standby consumption can be as much as 85 per cent of that in normal operation).
- Continued decline in UK manufacturing output - which could very well be one result of the continuation of high energy prices.

For scenario planning purposes, we have assumed that:

**Optimistic case:** demand is static at 2005 levels; i.e. any increase in demand through economic growth is cancelled out by efficiency improvements (note this is more ambitious than achievements over the last twenty years).

**Conservative case:** demand grows at 2.4 per cent a year - assuming the highest economic growth estimates, based on the Chancellor of the Exchequer's forecasts.

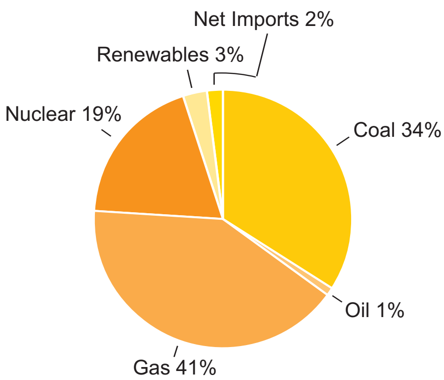
Demand and efficiency as a means of bridging the energy gap, is an issue which we will return to in a future paper.

## Appendix C

## Current Supply

Compared with many countries, electricity in Britain is supplied from a diverse range of sources, as shown in Figure 8 [3] (note that this diagram shows the proportions of actual energy supplied from each source):

Figure 8:
**Electricity supply mix 2004**




The generation capacity which provides this supply mix is [2]:

- Gas - 25GW capacity: The majority of this is modern Combined Cycle Gas Turbine (CCGT) plant, constructed since the beginning of the 1990s and which will be in commission to 2020.

- Coal and Oil - 31GW capacity: This is typically older plant and will require changes to meet the EU Large Combustion Plant Directive (LCPD). Note that **capacity** for coal is higher than gas, although gas generally provides more of our energy because the plant has higher **availability**.

- Nuclear - 12 GW capacity. A combination of older Magnox-fired stations and more modern Advanced Gas-Cooled Reactors, also one Pressurised Water Reactor (PWR). Much of this capacity - perhaps all but the PWR at Sizewell B - will end its operational life during the report period.

- Renewables - 1GW: The renewables sector is growing slowly but steadily. At the moment the majority of developments in this sector are in the construction of wind-powered generation.

- Interconnector - 2GW The cross-channel interconnector to France, which imports electricity, will remain in operation for the foreseeable future and is due to be upgraded. A further interconnection to the Netherlands is being added around 2010.

The nature of this mix has changed over the last 10-15 years, with a massive increase in the amount of gas-fired generation coinciding with a decline in the proportion of coal-fired and nuclear generation. The next 15 years will see continued massive change.

## Appendix D: Decline in Supply

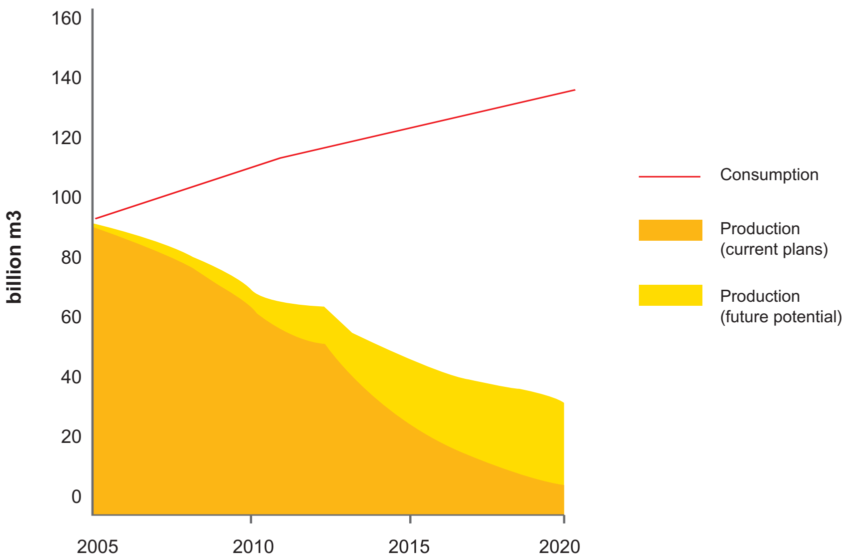
### D1: Source

#### Gas

Britain's gas supply has been relatively stable for the last thirty years and more, since the development of the UK Continental Shelf gas field. Throughout that period the vast majority of our gas supply has been provided from the North Sea fields, and since the interconnector to Zeebrugge was constructed in the early 1990s Britain has been a net exporter of gas. This is a situation which is changing abruptly; for the first time in many years consumption is now outstripping production, and Britain is once again becoming an importer of gas.

Even according to the most optimistic forecasts of production from within the UK, it is still clear that by 2020 at least half of our oil and gas will have to be imported. For example, Figure 9 below shows the UKOOA's projections [3] for future production from the UK Continental Shelf alongside their forecasts of our demand for gas:

Figure 9:
**Forecast gas production**




#### Coal

Although it has not received the high media coverage of our gas decline, our dependence on imported coal has also been increasing. In 1997 imported coal accounted for 31 per cent of our needs; by 2005, this had increased to 59 per cent. [20] The great majority of the UK's coal mining capacity has closed since the 1980s, as the indigenous product was unable to compete with cheap foreign imports. However, the recent sharp increases in energy prices generally have led to moves to re-open at least one UK pit.

Coal is a high producer of $CO_2$ and other gases that mean the share of coal in our generation is likely to decrease, therefore source is not seen as an issue. However, given the dramatic growth in coal consumption currently being seen in China in particular, the provision of coal is not without risk.

**D2: Generation**

**Nuclear generation**

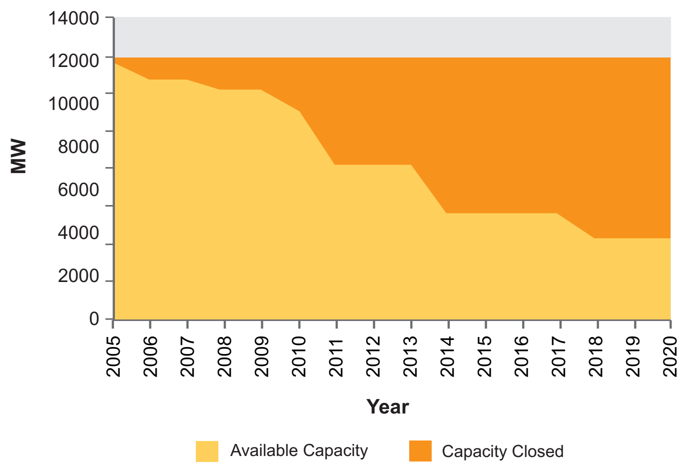
Britain currently has just under 12 GW of nuclear generation capacity, providing around 19 per cent of the country's electricity requirements. However, much of this plant is approaching the end of its operational life and is planned for closure over the next fifteen years. By 2020 it is forecast that only three nuclear stations will remain open, with a combined capacity of some 3.7 GW; these stations would then provide perhaps 7-8 per cent of the country's electricity. [2]

The current closure plan for the nuclear stations is shown in Table 2 below, and its impact can best be represented graphically as shown in Figure 10 below the table: [derived from 1, 2, 17]

Table 2:
**Planned nuclear plant closures**

| Station | Capacity MW | Published Lifetime |
|---|---|---|
| Dungeness A | 450 | 2006 |
| Sizewell A | 420 | 2006 |
| Oldbury | 434 | 2008 |
| Wylfa | 980 | 2010 |
| Hinkley Point B | 1220 | 2011 |
| Hunterston B | 1190 | 2011 |
| Hartlepool | 1210 | 2014 |
| Heysham 1 | 1150 | 2014 |
| Dungeness B | 1110 | 2018 |
| Heysham 2 | 1250 | 2023 |
| Torness | 1250 | 2023 |
| Sizewell B | 1188 | 2035 |

Figure 10:
**Planned nuclear plant closures**



It is possible that plant refurbishment projects and the scope for potential lifetime extensions could serve to extend the period over which closures of some nuclear plants take place. For example, British Energy has recently announced a ten-year extension to the operating life of its Dungeness B station, and is investigating a similar extension for Hunterston B. However, various sources agree that there is no prospect of extending the life of the older Magnox reactors now owned by the Nuclear Decommissioning Authority, all of which are due to close by 2010.

It will readily be appreciated that, unless action is taken to ensure that the capacity which closes is replaced, the loss of such a high proportion of the existing nuclear capacity will have a major impact on the development of the energy gap.

**Coal and oil-fired generation**

Much of our existing coal- and oil-fired generation capacity also faces closure over the next ten years. This is principally the result of the implementation of the EU Large Combustion Plants Directive (LPCD), which is aimed at reducing emissions in the EU of substances such as sulphur dioxide. The LCPD will require coal and oil-fired power plants to install flue gas desulphurisation (FGD) equipment, or else face limited operating hours and closure by the end of 2015.

At the time of writing it seems likely that a small number of power stations within the electricity generating industry (Drax, Eggborough, Peterhead and Longannet), together with most of the existing combustion plant in the non-power sector, will continue to operate under a National Emissions Reduction Plan (NERP). The remaining large power stations will either comply with the Directive by adopting a different approach, known as the emission limit values approach; or else opt-out of the LCPD completely by agreeing to only operate for a maximum of 20,000 hours after 1 January 2006 and to close by December 2015. Over half of the affected stations, many of which are reaching the end of their planned operating lives in any case, are expected to opt out of the LCPD and close by that year.

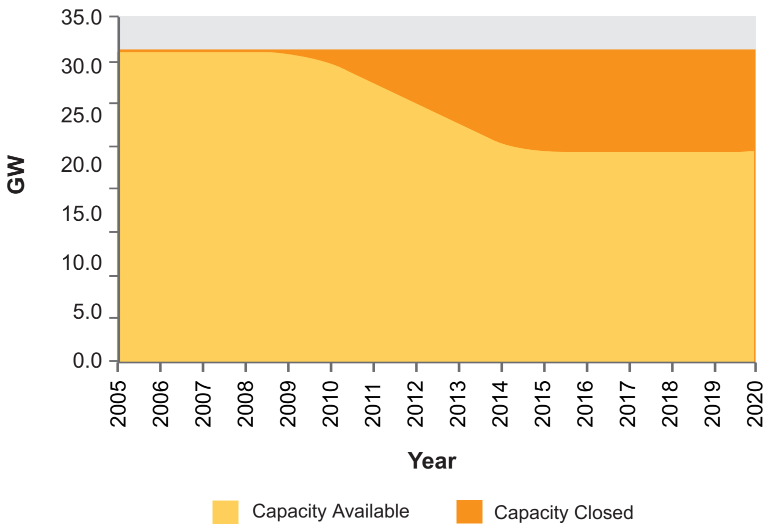
As a result, coal-fired generation is projected to decline sharply in the UK, from around a third to approximately 16 per cent of capacity by 2020. In absolute terms this amounts to a loss approaching 10 GW of generating capacity, but the exact figure will depend on how and when the operators of these stations implement the 20,000 hours limit over the coming years. A recent analysis [8] has identified the plant which is expected to close, and the capacity which will be lost, as shown in Table 3 opposite.

In Figure 11 opposite, we have attempted to specify which of the above stations will close when; but we have assumed that the 10GW of capacity will be closed at a steady rate between 2010 and 2015. In theory a station could use all of its available 20,000 hours by as soon as the second half of 2008, but as this type of plant typically operates at a load factor of around 65 per cent, the earliest closure date of 2010 seems more probable.

Table 3:
**Coal and oil plant closures**

| Station | Capacity MW |
|---|---|
| Cockenzie | 1152 |
| Didcot A | 1984 |
| Fawley | 500 |
| Ferrybridge Units 1 & 2 | 980 |
| Grain | 650 |
| Ironbridge | 964 |
| Kingsnorth | 1940 |
| Littlebrook D | 1370 |
| Tilbury B | 1050 |
| **Total** | **9690** |

Figure 11:
**Coal and oil plant closures**




While the effect of these closures may not appear so immediately dramatic as the nuclear plant closures, because the percentage of this type of generation to be closed is lower, it should be recognised that the absolute amount of capacity to be close is actually larger than for the nuclear plant. Thus the closure of so much coal and oil-fired generation will actually make a larger contribution to the energy gap than will the nuclear closure programme - though the latter has so far attracted a much greater share of the publicity over the issue.

## Appendix E: Future Supply

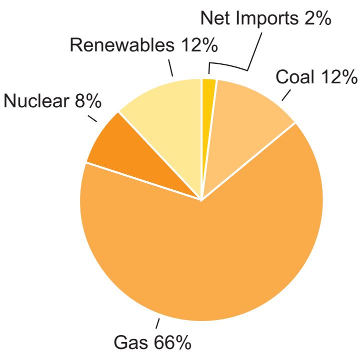
### E1: Overview

The major options for the future development of electricity supply may be summarised as:

- Gas: Continued construction of new CCGT plant on a large scale. The 2005 National Grid Seven Year Statement (SYS), for example [2], forecasts that 6.5GW of additional CCGT capacity will be constructed by 2012. The 2006 SYS, by comparison, suggests that this figure could be as high as 9.7 GW in the same period. A similar rate of construction would need to be maintained through to 2020 in order to meet the prediction (see Figure 12 below) that two-thirds of the UK's electricity will be generated from gas by that date;
- Coal: Investment in construction of new 'clean coal' generation plant
- Nuclear: The construction of a series of new nuclear power stations to replace the nuclear and coal-fired plant which will close during the period.
- Renewables: Continuing increase in the rate of construction of new wind, Combined Heat and Power (CHP) and other renewable plant, in line with the Government's target of increasing generation from renewable sources to around 20 per cent. The 2005 National Grid SYS, for example, forecasts that by 2012, there will be an increase of 5.5GW in wind generation capacity and more than 0.5GW of CHP capacity. The 2006 SYS, by comparison, forecasts that the increase in wind capacity by 2013 will be as much as 8.2 GW, with 3.3 GW of this to be constructed offshore;
- Efficiency: Dramatic changes to building regulations and significant investment in current industrial, commercial and housing stock to reduce energy usage. This option is not considered in detail in this paper - it will be the subject of a future paper. The 'optimistic case' assumption for demand includes the need to increase efficiency over historic achievements.

One projection of the resultant fuel mix, as predicted by the Department of Trade and Industry (DTI) [3], is as shown in Figure 12 (in the same way as with Figure 8, this shows the predicted sourcing of the electricity consumed, as opposed to the amount of available capacity):

Figure 12:
**Forecast electricity supply mix 2020**




There are, however, many uncertainties in such a scenario. For example:

- Gas: will the gas be available to fuel the generation? Will companies build CCGTs without firm commitments on the availability of gas and a clear carbon policy?
- Nuclear: Will there be public and political consensus on these? Will planning regulations enable them to be built? Can they be built in time?
- Coal: Will companies invest in clean coal generation plant without a clear government mandate and long term price of carbon? Is this dependent on the development of carbon abatement technology?
- Renewables: Will these prove economic and can they be scaled up in time? There is much focus on wind, but will wind be available during the coldest winter days? The largest renewable opportunities are in Scotland, but significant investment in the transmission network, 'the wires' is required to bring this South.

These are discussed in more detail opposite.

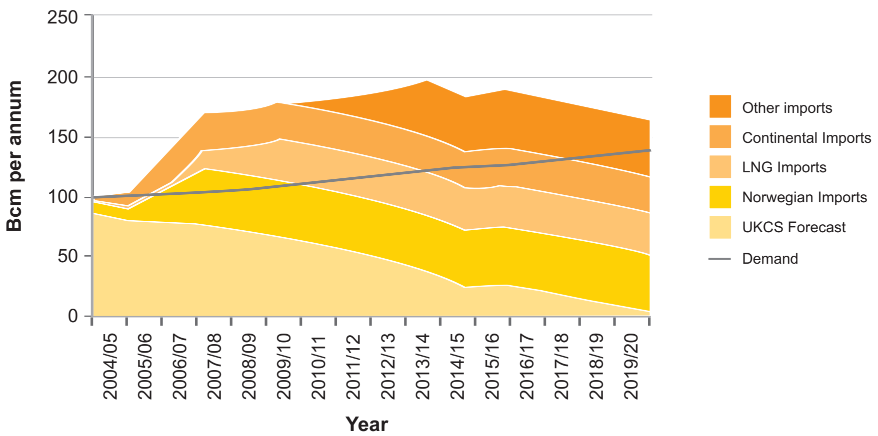
**E2: Source - gas**

As discussed in Appendix D, the UK is increasingly dependent on imported gas. From around 2015 Britain will need to import increasing quantities of gas from sources which are not currently identified and for which no long-term contractual arrangements currently exist. At the same time the production of gas from the UK Continental Shelf will continue to fall steadily - it has been predicted that without sustained investment in future production, the UK could be importing 40 per cent of its gas and oil needs by 2010, and 90 per cent by 2020. [derived from 1, 3, 4, 17]

The key question then, of course, is where the required imports will come from. At present about 70 per cent of our gas imports come from Norway. The new Langeled interconnector from Norway is due to commence operation in 2006, and supplies from that source are contracted for at least ten years. It will have an initial capacity of 38 million $m^3$ a day, or around 14 billion $m^3$ a year, equivalent to approximately 15 per cent of our current requirements (as shown in Figure 6, the latter are currently of the order of 100 billion $m^3$ a year). In addition, the existing interconnector between Zeebrugge and the Bacton terminal was upgraded from a capacity of 8.5 billion $m^3$/year to 16.5 billion $m^3$/year on 8 November 2005. A second phase enhancement, due to be completed by December 2006, will bring the total import capacity of the interconnector to 23.5 billion $m^3$/year, or about 25 per cent of our current requirements (but of course the latter will continue to grow, as shown in Figure 13 below and discussed in Appendix C earlier). [from 3, 4 various]

The other option for importing gas is to bring it from further afield in the form of Liquefied Natural Gas (LNG). This is a method which was used in the past, but the LNG terminal on Canvey Island was closed in the 1970s once the abundance of cheap gas from the North Sea field rendered this uneconomic. Now this technology is being revived, and a number of new terminals are under construction. However, the current level of capacity is still very small. In any case, even if imports from Langeled continue at the same rate once the initial contract expires, by 2020 the decline in production from the UK Continental Shelf means an increasing reliance on imports of gas from outside continental Europe. Figure 13 below is extrapolated until 2020 from figures produced by the UKOOA, and quoted in the energy review consultation paper [1]

Figure 13:
**Forecast gas supply and demand**

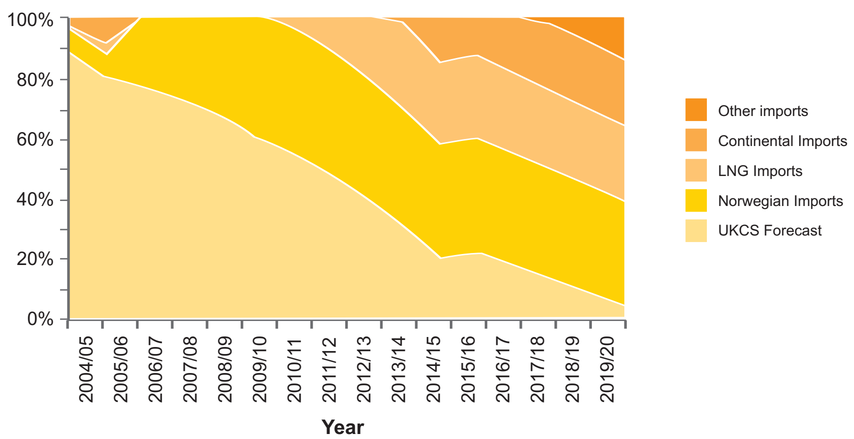


It will immediately be clear from this that, even given the contributions from Norwegian supplies and from LNG, by around 2014-2015 the UK will need to import significant quantities of gas and oil from other sources, initially from Europe and then from further afield. Questions have already been raised about the potential political instability of some of the ultimate sources of these supplies. More worryingly, however, recent events have shown that even the supplies of gas from continental Europe cannot be relied upon. In the early part of 2006, cold weather in the UK meant that gas prices here reached unprecedented levels; but European companies nevertheless chose not to sell additional gas to the UK, in spite of the attraction of high prices. Their traditional public service obligations, coupled with slow progress in market liberalisation, mean that continental utilities are unwilling to sell gas from their storage to the UK that they may need for their domestic customers, even if this would net them a handsome profit.

The situation was highlighted with unprecedented clarity on 13 March 2006, when, following a fire at the Rough storage depot, and with heavy snowfall occurring in Scotland, National Grid issued its first ever Gas Balancing Alert. This was to warn gas shippers and traders, as well as industrial users, that demand for gas was in danger of exceeding supply - in which case action might have to be taken to cut off some industrial users. As a result, the spot price of gas in the UK quadrupled, to something approaching £2.50/therm - but this was still not enough to cause additional supplies of gas to be released from continental Europe. Even at such record prices, the interconnector continued to operate at only something like 50 per cent of capacity.

Arguably the most serious implication of this is that, if urgent action is not taken to resolve the situation and guarantee future supplies (and it is by no means clear what form such action could take in a free market), the large-scale industrial users of gas who could be cut off in future events of this type include the operators of gas-fired power stations. Many of these purchase their gas under long-term interruptible contracts, not least because the price of gas under this type of contract is lower. And with approximately 40 per cent of the UK's gas consumption being used to generate electricity, and up to two-thirds of the UK's electricity potentially being generated using gas by 2020, as discussed in the following section, a major interruption to gas supplies could have a calamitous impact on the generation sector. Figure 14 below throws the situation into even sharper clarity, showing in percentage terms the contribution which will be required from each source in order to fully satisfy the projected demand for gas:

Figure 14:
**Gas demand percentages**



What these figures show is that while the Langeled pipeline will initially supply around 15 per cent of the UK's gas requirements, as noted above, this figure is expected to increase rapidly and imports from Norway could reach 35-40 per cent of the total requirement. Similarly the requirement for LNG imports has to increase from its present negligible rate to meet some 25-30 per cent of the total. Thus it would only need a problem with the supply of gas from either of these sources to cause an immediate energy crisis in the UK. While there would of course be additional capacity available via the Zeebrugge interconnector, the recent history outlined above has shown that this cannot be relied upon - and in any case, as also mentioned earlier, at best (i.e. even after the planned upgrades) this interconnector can only satisfy some 20-25 per cent of our current requirements.

**E3 Generation - Construction of new gas-fired power stations**

As the previous diagram indicates, the expectation is that the construction of new gas-fired power stations will continue at a comparable rate to that which has been seen over the last ten years and more - amounting to a net increase of the order of a gigawatt of new capacity each year. Indeed, if the all of the new gas-fired capacity for which initial applications have been registered is eventually constructed, there could be as much as 14GW of new CCGT generation available by 2012. These stations are efficient (over 50 per cent), and relatively quick and cheap to construct - a construction programme of some eighteen months to two years is typical. [2]

However, the main constraints on the construction of new gas-fired stations are likely to be the availability and price of the fuel. Given the recent fluctuations in the price of gas, together with uncertainty about the reliability of supplies, there can be no guarantees of the availability of gas, for power generation or any other purpose. For companies looking to invest in the construction of new CCGT plant, the combination of these factors may well lead to a significant reduction in the rate of new build. Under free market arrangements, and with no government intervention, it can by no means be guaranteed that all the further construction which is currently planned will actually take place - or that future projects will be forthcoming at the same rate.

**E4: Generation - Construction of new nuclear power stations**

After a lengthy period in which there has been little or no nuclear plant constructed - over 80 per cent of the nuclear capacity currently operating is over 15 years old - a large number of countries are either constructing new nuclear plant or considering doing so. India is constructing ten new nuclear power stations, and the 1600MW European Pressurised Reactor plant being built in Olkiluoto in Finland will be the largest in the world.

It has been widely surmised that a decision to resume building new nuclear power stations will be one of the outcomes of the current energy review, and many commentators have concentrated on this aspect. However, there are many risks and potential delays to this process. The last time a new nuclear power station was constructed in Britain, at Sizewell B, the public inquiry alone took six years to complete and the station took ten years to build.

There have been significant improvements in build time and there are major opportunities around, for example, standardisation and pre-approval of designs, but there are still major risks to nuclear that lead us to question its capacity to fill the medium gap. These include:

- Government consensus: Will there be consensus within the government, recognising the probability of leadership change, and between parties that will ensure commitment to nuclear?
- Will the energy review give unequivocal support to nuclear, or will a further lengthy stage of consultation be required?
- Will there be a clear answer on the issue of waste? Is waste included in the economics for nuclear?
- Will it be possible to achieve planning permission for nuclear. It has been suggested that this could be overcome by using existing sites, but will these be decommissioned and prepared in time?
- Will rapid build times be achieved - the Finnish reactor has already announced a one year slippage.

We believe these issues can be overcome - this paper is not anti-nuclear, but it is important to question the extent to which nuclear may be able to fulfil the 2015 gap.

### E5: Generation - Adoption of new coal technologies

The development of new Clean Coal Technology (CCT) for coal-fired stations is another area which has attracted its share of publicity of late, not least because of the number of power stations being constructed in the Far East which use these technologies. The term CCT embraces a range of methods for improving the efficiency of coal-fired generation at the same time as reducing the levels of harmful emissions, for example:

- In the latest systems, called advanced supercritical boilers, the coal is pulverised before being burnt. These systems have an efficiency level of around 42 per cent. Replacing an old-style boiler, operating at about 30 per cent efficiency, with one of the new systems can cut $CO_2$ emissions by 23 per cent;

- In an Integrated Gasification Combined Cycle (IGCC) system, the coal is turned into gas and burnt, producing electricity and steam. The steam is then used to power additional turbines and create more electricity. As a result more electricity is generated with the same amount of coal; IGCC systems are around 45 per cent efficient, comparable to pulverised fuel plants. However, uptake so far has been limited by the cost advantage of gas fired plant and the reluctance of power plant operators to invest in the new technology while the economic case is still uncertain.

- Co-firing a mixture of coal and up to 20 per cent bio-mass also reduces emissions; however, anything more than 20 per cent of biomass involves the use of significant amounts of energy to transport the biomass fuel, so increases emissions in that respect.

Without a clear lead from the politicians, however, it seems unlikely that CCT will make a significant contribution to Britain's energy mix by 2020, as investigations into the use of this technology are still at a very early stage. The strategy for Carbon Abatement Technology (CAT) published by the DTI in 2005 [9] sets out a path for developing these technologies up to 2020 and beyond, but is primarily concerned with research and development and the establishment of pilot projects. For example, E.On has recently launched a study into the use of CCT, and is investing £540mn for Britain's first power station fired by CCT. An E.On spokesman said in January 2006 that the company could not give a timeframe of when the new station could be operational, but added that the power station 'would be the first of its kind.' These comments suggest that significant adoption of CCT is still a number of years away. Similarly for the development of Carbon Capture and Storage (CCS), which takes the carbon (and other pollutants) emitted during the generation process and stores it underground (e.g. in depleted gas or oil fields), the technology is at such an early stage of development that is seems unlikely to make a significant impact before 2020.

**E6: Generation - Developments in CHP and renewable energy**

One of the government's key targets in the Energy White Paper of 2003 [10] was that the use of renewable generation sources should grow from its present level of around 2 per cent, to 10 per cent of total demand by 2010 and 20 per cent by 2020. However, achievement of this is dependent on a number of assumptions - the timeline in the White Paper suggests that biomass generation 'may be economically viable' in the mid-2010s, and wave and tidal technologies some time between 2010 and 2015 - or even later.

The major success story in the renewables sector, of course, is wind energy. Approximately 1.3 GW of wind generation capacity is currently recorded by National Grid in the Seven Year Statement [2], and this is forecast to grow to 6.8 GW by 2012 - by far the largest percentage increase of any generation sector. The 2006 SYS, indeed, updates this figure still further, to a total of 8.2 GW. And there are many more smaller-scale projects in operation and under construction which do not appear in the SYS, being classified as embedded generation (i.e. generation connected at the 132 kV level and below, the effect of which is netted off within the local supply area[3]).

It is clear that the current growth in wind generation will continue for some time to come. At a recent conference a speaker from National Grid identified the potential for the construction of a total of some 16 GW of onshore wind generation (including that which appears in the SYS) in Scotland alone - plus a further 8GW offshore (2GW in Scotland and 6 GW in England and Wales).

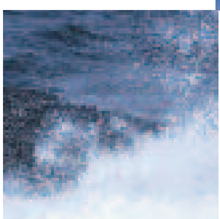
At first sight, therefore, all of our electricity needs could apparently be met by the construction of yet more wind farms - Britain being the most windswept country in Europe. However, a word of caution is needed here, owing to the intermittent nature of wind generation (a characteristic which is shared by other types of renewable generation as well). Not only do wind turbines not work when the wind doesn't blow; they also cut out when it blows too hard (above wind speeds of around 25 m/s). It is generally reckoned that the percentage of the registered capacity of this type of plant which will be available at any one time is around 25 per cent, and this is the figure which we have used later in our scenario analysis. Supporters of wind generation argue that this intermittency can be dealt with simply by building more wind farms; and at least one campaigner [11] takes this to the extreme of claiming that in order to guarantee a certain level of capacity from wind generation, all that is necessary is to install capacity capable of ten times the required level. In other words, in order to guarantee availability of (say) 5 GW of wind generation, it is necessary to install 50GW of capacity - because at least 10 per cent of the installed capacity will always be available.

A further government objective, of having at least 10GW of CHP capacity installed by 2010, was set as part of the Climate Change Programme. At the end of 2003, installed CHP capacity, as recorded by National Grid in the Seven Year Statement, had reached 4.9GW, about 4GW of which was accounted for by embedded generation. With total installed CHP capacity having risen by only 200MW since 2000, the 10GW target looks increasingly ambitious, requiring as it does the development of new capacity at a rate in excess of 700MW per annum. By contrast, the National Grid

Seven Year Statement predicts a net increase in CHP capacity of just 560 MW by 2012. Similarly the growth in embedded generation of all types - not just CHP - which is predicted in the Seven Year Statement is negligible; remaining at around its present level of approximately 3.5 GW for the period of the forecast.

A recent report from the Carbon Trust [12], urges the government for more support for the development of new renewable technologies. If support is forthcoming, the Trust predicts that wave and tidal technologies, for example, could be providing 3 per cent of UK electricity supply, or a sixth of the government's 20 per cent renewables aspiration, by the year 2020. 'Beyond 2020, the industry could develop considerably further', the report notes. But the economics of the technologies need to fall considerably before these are competitive, as estimates for tidal generation currently sit at between 10-15p.kWh, while wave energy is between 20-25p/kWh.

Another problem with major growth in the renewables sector is that as many types of renewable generation - and particularly wind generation - are intermittent, as discussed above, much larger proportions of renewables in the generating mix could in the longer term increase the amount of flexible back-up capacity required for the electricity network. With large proportions of renewables on the system, additional back-up (likely from coal, oil or gas) would tend to add to the cost and technical complexity of system management. This situation is already causing problems for renewables under the current electricity trading arrangements, and has been the subject of trenchant criticism by Professor David Bellamy amongst others. It is entirely conceivable that in order for the government's targets for renewable generation to be met, a further major restructuring of the electricity trading arrangements[4] will be necessary.



3

More properly referred to as 'below the Grid Supply Point'.

4

The original trading arrangements, known as the Electricity Pool, which were introduced when the electricity industry was privatised in 1990, were replaced in 2001 by the New Electricity Trading Arrangements (NETA). The NETA arrangements for England and Wales were extended to include Scotland in 2005, but without significantly changing the arrangements themselves.

**Developments in microgeneration**

The Government's Energy White Paper of 2003 looks forward to a very significant increase in the level of generation to be provided from distributed sources, including microgeneration - that is to say, generation units which can be installed at the domestic level, not just in industrial or commercial premises. The strategy for Combined Heat and Power (CHP) published by Defra the following year sets a target for 400 MW of CHP to be provided by microgeneration units by 2010. At a typical size of 1 kW per unit, that will require the installation of some 400,000 of these units (the current installed baseline being negligible) in the next five years.

Following on from this, the Government's strategy for microgeneration has just been published by the DTI [13]. The strategy does not set any specific targets for the development or implementation of microgeneration, restricting itself instead to more general objectives. However, a report recently published for the DTI by the Energy Saving Trust and others [18] suggests that there could be up to 8 million units of microgeneration installed by 2050, and this has been interpreted as meaning that microgeneration could supply some 35-40 per cent of our domestic electricity needs by that date. On the other hand, the report also concludes that at the present rate 'it could take another 10-15 years before a significant proportion of domestic energy is generated by this technology'. The predictions for the years to 2020 show only relatively minor market penetration (c. 300,000 units installed) in all scenarios except one - this being where government regulations require all new domestic build to install microCHP units, in which case the 2020 figure could be 22.5 GW, or over 25 per cent of the UK's required capacity. Failing such government intervention, the rate of uptake is likely to be relatively slow.

A key question for the development of microgeneration technologies is the financial break-even point for each. The DTI study [14] on suggests that several technologies - notably micro-wind and micro-CHP - could become cost-effective by 2020. However, the majority of these scenarios require the principle of Energy Export Equivalence (EEE) to be adopted - i.e. that the price paid for electricity exports is equivalent to that for imports. At the moment there is a significant price differential - around 2.5 - 3 p/kWh being paid for exports as opposed to c. 7.5 p/kWh for imports. In order to overcome this and other obstacles to the expansion of microgeneration, such as the metering arrangements and the cost of metering, the DTI's strategy paper suggests that here again changes to the electricity trading arrangements may be necessary, and urges the various interested parties to work together to achieve this.

**E7: Reinforcement of the transmission network**

As a final consideration in this section, if large quantities of new generation are to be constructed in new locations, the ability of the transmission network to accommodate the resultant power flows becomes a significant consideration. In particular the need to enable the connection of large quantities of new wind generation, both in Scotland and offshore, poses significant problems for the transmission network operators (National Grid in England and Wales, ScottishPower and Scottish and Southern in Scotland).

A recent study by the transmission operators identified a range of possible network reinforcements, requiring investment ranging from £500-£1500 million, as shown in Figure 15 below. [24]

In addition to this, further estimates, in the range £275-£615 million, have been drawn up for the cost of accommodating the offshore wind farms to be developed around the coasts of England and Wales.

Because of their monopoly position in their respective areas, and the fact that the costs of these investments are ultimately recovered from consumers, the transmission operators cannot simply press ahead with these projects; they first have to be agreed with Ofgem. And a key concern in the approval process is the establishment of confidence that the new projects will actually be built; otherwise the expense of the reinforcements would be incurred to no purpose. For the time being, Ofgem has given approval for a limited number of the above reinforcements to go ahead, as shown in Figure 16 below, at a total cost of some £560 million. A consultation will be held as to how the cost of reinforcements for offshore projects will be funded.

It should be noted, however, that approval from Ofgem for the reinforcement work on the old Scottish interconnectors is conditional upon planning permission being granted for the central Beauly Denny reinforcement. Given that past experience, for example in north Yorkshire, has shown that the planning process can take a number of years to negotiate, there is a risk that the network reinforcements to accommodate some of the new Scottish wind farms may not be completed before the wind farms themselves are ready. However, the arrangements for transmission charging which will pay for the reinforcements should ensure that financing will not be a problem, once the necessary approvals are in place.

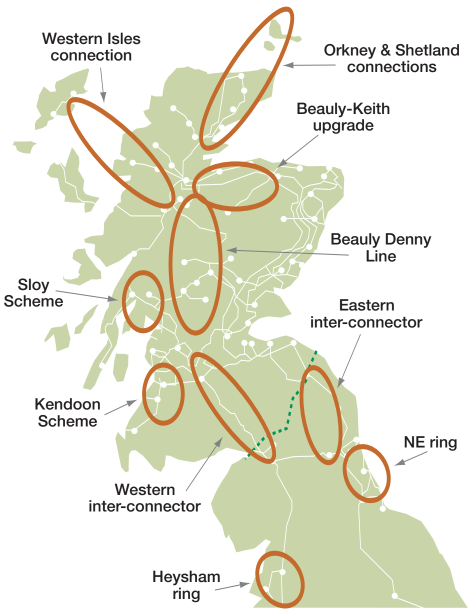



Figure 15
**Proposed network reinforcements**

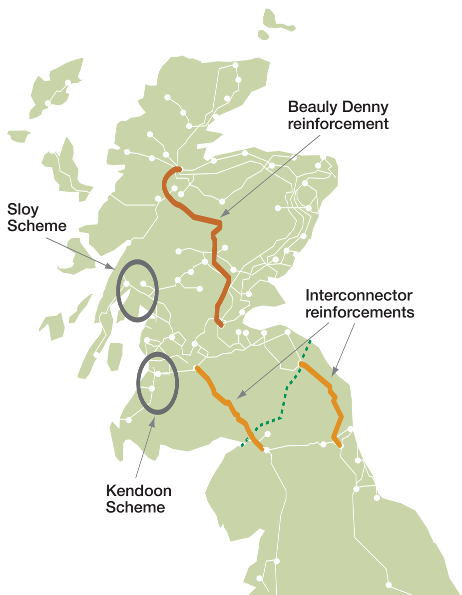



Figure 16
**Approved network reinforcements**

## Appendix F Scenario Assumptions

The most comprehensive and reliable source of data for the scenarios is the National Grid Seven Year Statement (SYS) [2] and we have used this data as our starting point. This gives projections of the peak demand in each year against the expected growth in capacity.

In all the scenarios we have grouped the generation which is listed in the SYS into five categories, as follows:

- Nuclear
- Coal and oil - predominantly the former
- CHP and renewables - increasingly dominated by wind generation, but also including hydro, both traditional and pumped storage, and CHP
- Interconnectors - a relatively small category but not one which can readily be incorporated with any of the others
- Gas - predominantly CCGT, but also including open cycle plant. Because of the importance of the sourcing of the gas, we have shown UK and foreign derived gas separately, with the assumption that these will be in the same proportions as gas consumption generally

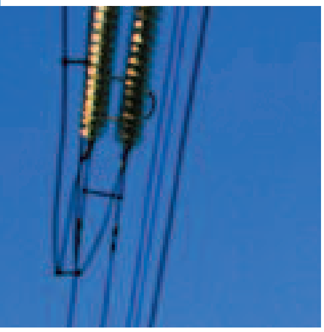
In all the graphical depictions of the scenarios the generation capacity is shown in this order, reading from nuclear at the bottom to imported gas at the top.

### Peak Demand Scenarios

National Grid consider three different scenarios for the growth in demand at the annual, corresponding to different rates of economic growth. In order to avoid over-complication we have taken their 'base' scenario' as the basis for our scenarios. We have also used their 'high' demand scenario as part of our 'conservative case' scenario.

The National Grid base case scenario is predicated on 2.7 per cent per annum growth in the economy, whereas in his 2006 Budget, the Chancellor of the Exchequer predicted a growth rate of 2.75 per cent per annum for 2007-2008. We have adjusted the National Grid forecast figure in line with the Chancellor's, but the effect of this is only to make demand for electricity grow by 1.375 per cent per annum instead of 1.3 per cent. Similarly their 'high' demand case is based on 3.1 per cent growth per annum, whereas the Chancellor predicts 3.25 per cent - which instead of 2.2 per cent growth per annum in electricity demand gives a figure of 2.4 per cent.

The assumption we have used for capacity is that at times of peak demand, all generation will be available at 100 per cent availability unless otherwise stated for a particular scenario. This is broadly in line with experience, but will, however, overstate the amount of capacity available from the CHP and renewables sector. For this sector we have assumed that 50 per cent of the registered capacity, or twice the normal level, will be available.



### Average Demand Scenarios

Consideration of peak demand alone gives rise to a potentially misleading picture, since considerable efforts are made to maximise the amount of plant which is available at the likely peak times each year. So in addition to this, we have considered a second set of scenarios based on the average levels of demand and availability of the various plant types. This has involved making a number of assumptions and approximations, which are justified below.

In order to establish an average figure for demand, we have analysed the information available on the Balancing Mechanism Reports web site, www.bmreports.com, [23] which is managed by LogicaCMG on behalf of ELEXON. This site records (amongst much other information) the half hourly data produced by National Grid from their operational metering, and published as Initial National Demand Out-turn (INDO). Analysis of this data (which is published for each half hour, and represents the average MW value in the half hour), indicates that a typical average value for demand in a day is approximately 60 per cent of the annual peak demand value. We have accordingly used this percentage of the peak demand in constructing our 'average demand' scenarios.

Our estimates of the average quantity of generation available are based on the actual availability of plant as published in the DTI Digest of UK Energy Statistics (DUKES), [15] and specifically Table 5.10 - Plant loads, demand and efficiency. We have used the availability figures (where available) averaged over the four years since 2001, when the New Electricity Trading Arrangements (NETA) came into operation; as this change resulted in significant alterations in the way in which coal plant in particular is operated. The average availability figures which result are as follows:

- Nuclear - 75 per cent, which corresponds exactly with the published figures available from the operators' web sites;
- Gas - where the figure published is for CCGT plant, which is the type of gas-fired plant which can be expected to most available, 65 per cent;
- Interconnectors - for which the data is not published in DUKES, so we have used the overall industry average of 54 per cent;
- Coal and oil - where we have used the figure published for coal-fired plant, which is typically available more frequently than oil-fired plant, of 60 per cent
- CHP and renewables - the figures published are only for natural flow and pumped storage hydro, at 30 per cent and 10 per cent respectively. The figure we have used as an average for this sector is therefore based on these figures and data available from web sites such as www.your-energy.co.uk, [25] which indicate that the typical availability to be expected from a wind farm is of the order of 25 per cent. As this is consistent with the figures published in DUKES for hydro-electric generation we have used this figure as the average for the sector.

## Appendix G - References

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32 Joint Energy Security of Supply Working Group Sixth Report April 2006



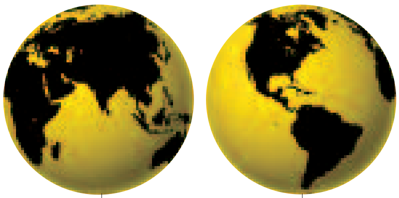
## Appendix H - Population Statistics

The paper uses outages across areas of the UK for illustrative purposes. These are based on statistics from:

http://www.statistics.gov.uk/regionalsnapshot/

| Area | Population (m) |
|---|---|
| Scotland | 5 |
| North West | 6.8 |
| North East | 2.5 |
| Yorkshire & Humberside | 5 |
| West Midlands | 5.3 |
| East Midlands | 4.3 |
| Wales | 3 |
| Eastern England | 5.5 |
| South East | 8 |
| South West | 5 |
| London | 7.5 |

It should be noted that these are used for illustrative purposes only to indicate the scale of the potential problem. Power cuts and supply problems would manifest themselves in a whole range of ways across the country depending on the specific problem, the configuration of the network and how energy companies sought to manage the problem in order to manage disruption.



Australia
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France
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Hungary
India
Indonesia
Ireland
Italy
Japan
Kuwait
Luxembourg
Malaysia
Mexico
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**LogicaCMG**
**Energy & Utilities**
Stephenson House
75 Hampstead Road
London NW1 2PL
Telephone: +44 (0)20 7637 9111
Fax: +44 (0)20 7446 4614
energy&utilities.uk@logicacmg.com
www.logicacmg.com